Kensington Energy Ltd.

2003 Annual Report

KNN

Contents

Corporate Profile

Kensington Energy Ltd. is a Calgary-based independent junior energy company engaged in the exploration and production of petroleum and natural gas in western Canada. The Company's asset base is located in a southeast to northwest producing corridor of Alberta. Kensington's common shares trade on the Toronto Stock Exchange under the trading symbol "KNN".

Annual and Special Meeting

The annual and special meeting of shareholders will be held at 3:00 p.m. on Tuesday, June 1, 2004 in the Viking Room of the Calgary Petroleum Club at 319-5th Avenue S.W., Calgary, Alberta.

Dean G. Anderson
Vice President, Operations

Scott T. Bonli
Vice President, Finance & Chief Financial Officer

Donald S. Wood
President & Chief Executive Officer

Jim Look
Vice President, Exploration

THINKING

Growth

Kensington has a specific expertise along a corridor of multi-zone, natural gas opportunities. In 2003, the team drilled 14.5 net wells with a 96 percent success rate, resulting in a 187 percent increase in production to 820 boe per day. Undeveloped land grew by 25 percent to 40,163 net acres.

Value

In 2003, Kensington exceeded 100 percent per share growth in production, cash flow and earnings. Proved reserves increased by 70 percent. The team replaced 2003 production by a factor of 4.3 times.

Quality

Kensington has an experienced management and exploration team with a sound business plan. Production in 2003 was weighted 78 percent to natural gas and featured an average netback of $22.82 per boe. Operating cost performance has consistently performed better than $6.00 per boe.

Highlights

Financial

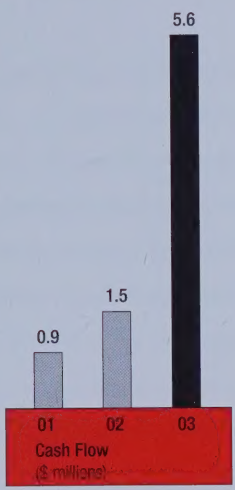
($ thousands except share data)	2003	2002	% change
Petroleum and natural gas sales	11,007	3,259	238
Net income	1,722	196	779
Per basic and diluted share	0.04	0.01	300
Cash flow from operations	5,556	1,513	267
Per basic and diluted share	0.14	0.05	180
Capital expenditures (net of dispositions)	13,371	9,873	35
Working capital (deficiency)	3,361	(3,650)	–
Shareholders' equity	25,999	9,621	170
Total assets	35,059	17,312	103
Class A common shares outstanding			
Weighted average			
Basic	39,486	29,420	34
Diluted	40,722	29,803	37
Year end			
Basic	49,119	29,428	67
Diluted	52,021	30,678	70

Operating

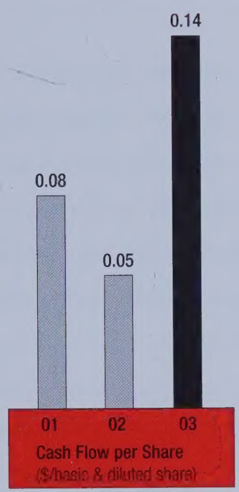
(6:1 boe conversion)	2003	2002	% change
Production			
Oil and NGLs (bbls/d)	182	111	64
Natural gas (mcf/d)	3,829	1,050	265
Barrels of oil equivalent (boe/d)	820	286	187
Prices			
Oil and NGLs ($/bbl)	35.36	37.04	(5)
Natural gas ($/mcf)	6.20	4.59	35
Barrels of oil equivalent ($/boe)	36.79	31.24	18
Operating netbacks ($/boe)	22.82	21.39	7
Reserves			
Crude oil and NGLs (mbbls)			
Proved	550	307	79
Proved plus probable [1]	729	642	14
Natural gas (mmcf)			
Proved	8,907	5,350	66
Proved plus probable [1]	10,575	10,755	(2)
Barrels of oil equivalent (mboe)			
Proved	2,035	1,199	70
Proved plus probable [1]	2,491	2,435	2
Undeveloped land (net acres)	40,163	32,200	25
Drilling activity			
Gross wells	20	13	54
Net wells	14.5	10.3	41

[1] *Represents established reserves in 2002.*

Charting a Year of Growth

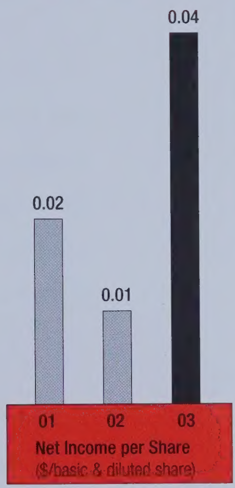


Stronger cash flow was driven by increased production and higher natural gas prices.

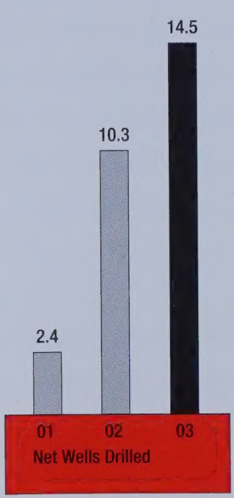


Achieved higher per share cash flow despite two equity financings and higher weighted average shares outstanding.

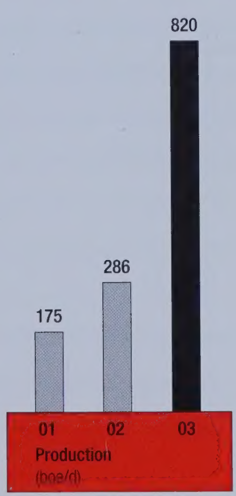
Increased production, higher operating netbacks and the benefits of tax rate reductions delivered increased net income.



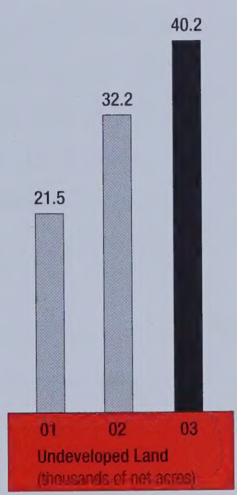
Per share net income increased by 300 percent.



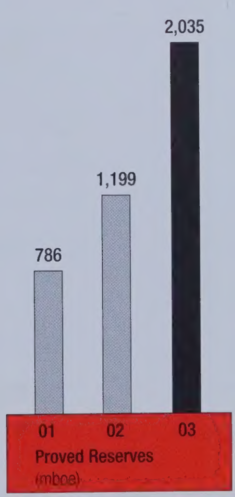
We executed a record drilling program of 20 wells with 96 percent success. Eight of the wells were exploratory.



Production per weighted average share grew by 113 percent in 2003. We exited 2003 with production of 1,148 boe per day.



We invested $1.0 million in land additions in key areas, creating a strong platform for growth.



We replaced 380 percent of 2003 production on a proved basis at an FD&A cost of $12.04 per boe.

President's Message to Shareholders

Two thousand and three was a period of substantial achievement for Kensington during which we enhanced our foundation for long-term growth with a strong exploration program, two significant transactions and record financial and operating results. Kensington's growth in 2003 benefited from the application of new technology to focused development and exploration plays within the Company's operating corridor. A key to the Company's operating performance was a commitment to original thinking and a drive for excellence in every aspect of our business.

The Company excelled in all areas of its business plan during 2003, achieving its strongest-ever performance gains and return to shareholders. Disciplined implementation of the business plan – including a balance of exploration, development and acquisitions – established a strong inventory of drilling prospects, positioning the Company for growth over the long term.

The momentum established by our exploration and development program realized significant performance improvements during 2003, generating year-over-year growth per share in production, cash flow and earnings that exceeded 100 percent. Drilling activity reached record levels in 2003. The Company drilled 20 wells with a 96 percent success rate. The majority of the drilling program focused on the key areas of Markerville and Compeer, and generated large percentage increases in production and reserves during the year.

The depth and scope of the Company's exploration plans in 2004 have been enhanced by two corporate acquisitions with prospective undeveloped lands plus successful land acquisition activity and farm-in negotiations in west-central Alberta.

The Company achieved successive production increases during each quarter of 2003, approximately tripling production during the 12-month period, and surpassed the milestone of 1,000 barrels of oil equivalent per day before year-end. We look forward to continuing these strong rates of production growth during 2004.

THINKING CORE AREAS

Our core areas offer multi-zone, high-quality natural gas reserves. In 2003, we expanded our holdings at Markerville, and acquired a presence at Worsley in the Peace River Arch. An acquisition in early 2004 provides exploration-rich opportunities in west-central Alberta.

Implementing our Business Plan

As stated in the Company's 2002 annual report, Kensington's business model has two elements. First, we explore and develop internally-generated prospects that target high quality natural gas reserves in western Canada. Second, we facilitate our exploration ideas and growth objectives with complementary strategic acquisitions, industry farm-ins and joint venture partnerships to gain greater access to land. Kensington's goal is to create significant shareholder value by focusing on natural gas and growing production. Our near term objective is to grow production to greater than 5,000 barrels of oil equivalent per day.

Kensington completed two equity financings during 2003, raising gross proceeds of $16 million to support our expanding exploration program. The Company graduated to the Toronto Stock Exchange from the TSX Venture Exchange in May 2003 and began trading under the new symbol of KNN. Increased trading volumes and a higher share price followed the Toronto Stock Exchange listing.

Kensington finished the year with a very strong balance sheet. This positioned us to complete two corporate acquisitions in the first quarter of 2004 for $29 million. The transactions, with 90 percent of the assets located in west-central Alberta, include opportunity-rich exploration land and long reserve-life natural gas production on trend with the Company's exploration areas.

1,700 boe per day at March 30, 2004

We added volumes at Markerville and Compeer late in Q1 and 500 boe per day by acquisition during the quarter.

Strong production growth

High netback production

$22.82

per boe in 2003

This reflects a corporate natural gas price of $6.20 per mcf, an oil price of $35.36 per barrel and operating costs of $5.63 per boe.

Kensington's current activity is focused on an exploration corridor targeting multi-zone opportunities at medium drilling depths. The corridor trends in a northwest direction from our original lands at Compeer in southeast Alberta through the central part of the province to the north side of the Peace River Arch at Worsley. Early exploration success and the initial availability of land at Markerville and Compeer enabled the Company to establish and grow these central and southeast areas substantially in 2003.

Longer-term, the Company intends to implement a westward migration strategy for 50 percent or more of our operations as we pursue larger, medium-depth targets in the multi-zone western part of the Western Canada Sedimentary Basin. Several initiatives reflect this longer-term strategy. We increased our presence at Markerville in 2003 through a five well drilling program which by year end was generating 34 percent of the Company's producing sales volumes. We acquired 10,000 net acres of undeveloped lands and production of 50 barrels of oil equivalent per day at Worsley in the second quarter of 2003. Finally, in 2004 we recently closed a $25 million private-company acquisition with producing assets and undeveloped land concentrated in west-central Alberta.

The Company will continue to focus on finding quality assets in areas that offer superior growth potential and where Kensington's technical expertise provides a continuing advantage. We will continue to pursue acquisitions within our core areas that extend our exploration program and allow us to at least match the growth rate of the past three years.

THINKING LAND

Land is the fuel that drives our exploration program. We currently hold more than 60,000 net acres of undeveloped land, with increases in the past year at Markerville, Worsley and west-central Alberta.

2003 Operating and Financial Results

Production increased significantly to an average of 820 barrels of oil equivalent per day, representing a 187 percent increase over the average production level of 286 barrels of oil equivalent per day in 2002. Production per share grew by 113 percent during the year. The Company's fourth-quarter production increased to 1,148 barrels of oil equivalent per day, weighted 81 percent to natural gas.

Major producing areas, and their respective percentage contribution to total production in 2003, were Markerville (34 percent), Compeer (21 percent), and Highvale (16 percent). Mid-year, the Company accomplished a significant disposition of the mature oil-producing property at Giroux Lake for $3.9 million in cash. The property had production of 100 barrels of oil equivalent per day. Kensington redeployed the sale proceeds into higher growth opportunities focused on natural gas.

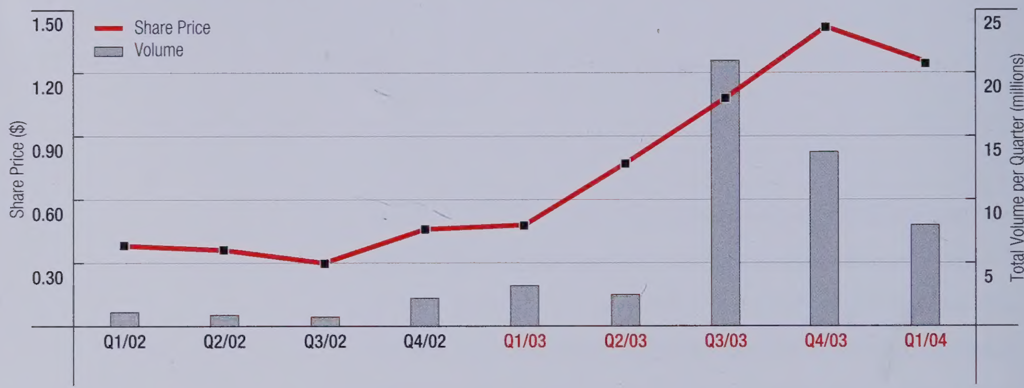
Cash flow was $5.6 million in 2003, an increase of 267 percent from $1.5 million in 2002. Cash flow per share increased by 180 percent to $0.14 per share from $0.05 per share in 2002. The primary drivers for our 2003 performance were strong natural gas production gains from the Company's exploration program combined with a 35 percent increase in realized natural gas prices at the wellhead.

The Company's corporate reserves were evaluated by the independent engineering firm Gilbert Laustsen Jung Associates Ltd. in

In 2003 we replaced production 4.3 times on a proved basis and 2.7 times on a proved plus probable basis.

Strong reserve replacement

SHARE PRICE AND TRADING VOLUME



2003 and in prior years by Martin & Brusset Associates. The 2003 capital program delivered strong reserve additions at effective finding and onstream costs. More than 380 percent of production was replaced on a proved basis at a finding, development and acquisition cost (including future development costs and revisions from prior years) of $12.04 per barrel of oil equivalent. Reserve additions, net of revisions, resulted in a 70 percent increase in proved reserves (26 percent growth per share) during the year.

Kensington believes that balance sheet strength is essential to implementing a growth-oriented business plan. At year-end 2003 the Company had no bank debt and cash reserves, adjusted for working capital, of $3.4 million. The Company's approved bank line at year-end was $5 million, and was increased to $14.3 million in the first quarter of 2004, based on our reserves evaluation and with inclusion of the recently acquired west-central Alberta assets.

Outlook for 2004

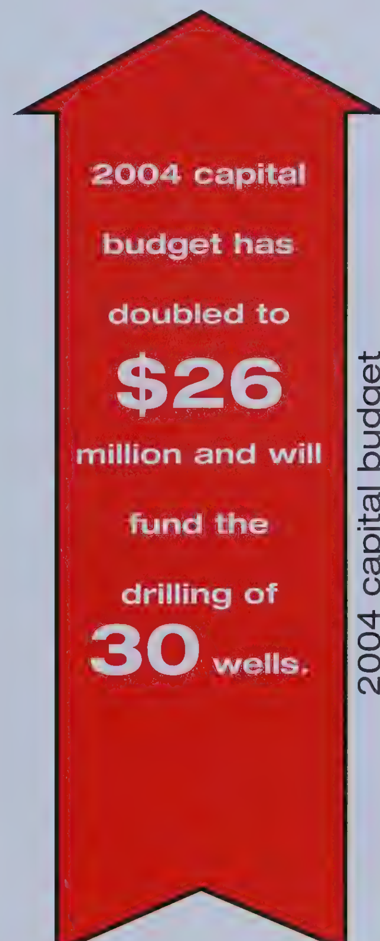
Kensington's measurable progress during 2003 confirms the soundness of our business plan and management's dedication to achieving our stated objectives. Our plan is well supported by favourable commodity prices and projected strong demand for natural gas over the next several years. Kensington's experienced management and technical teams have established a strong platform for growth during the next 12-18 months, based on an inventory of quality assets and drill-ready locations.

The Company's strong financial position has enabled it to capitalize on two significant acquisitions totalling $29 million during the first quarter of 2004. The new assets are opportunity-rich and primarily focused within Kensington's exploration corridor in west-central Alberta. With

THINKING NATURAL GAS

A majority of our capital program is directed to finding or developing natural gas reserves. In 2003, production was weighted 81 percent to natural gas. We increased both total proved producing and total proved natural gas reserves by 86 and 67 percent, respectively.

the completion of these transactions, the Company has increased its 2004 budgeted capital expenditures (excluding acquisitions) to $26 million. This will fund the drilling of approximately 30 wells in 2004, representing an approximate 50 percent increase over drilling activity in 2003.



Acknowledgements

We wish to express our sincere appreciation to our employees and consulting associates for all their hard work and significant contributions during 2003. We welcome Tom Love as a new director effective February 2004. Mr. Love, with an extensive background in Canada's oil and natural gas industry and the financial services sector, will additionally serve as chairman of our audit committee. We extend our appreciation to Clarence Chow, who stepped down from the Board in February 2004 for his contributions to the Company during the past year. We thank our entire Board of Directors for their guidance and support during this period of active Company growth and evolving industry regulatory standards. Most important, we thank our shareholders for their continued interest and support. We look forward to 2004 with every expectation for continued growth and success.

On behalf of management and the Board of Directors,

Donald S. Wood
President and Chief Executive Officer
April 12, 2004

Review of Operations

Two thousand and three was a high-impact year for Kensington Energy. We expanded our production base and land inventory in the original focus areas of Markerville and Compeer. We acquired a new area at Worsley with undeveloped land. We also completed a number of low-risk property and production purchases in central Alberta that added cash flow and hydrocarbon reserves.

Kensington uses a multi-disciplinary technical team approach to finding and developing oil and natural gas reserves. We are focused on a specific corridor that extends from eastern Alberta to the Peace River Arch. We assess our core areas within this corridor using regional geological, geophysical and engineering studies. We focus on areas of interest where there is an opportunity to acquire Crown or private land and where there is available infrastructure. We apply state-of-the-art technology, including petrophysical analysis, seismic and drilling/completion techniques, that reduces risk and enhances our success rate.

In order to control the timing of exploration and development activities and allocation of capital, we operate over 90 percent of our production.

In 2003, we had production gains in Markerville, Compeer and central Alberta. We acquired undeveloped land and production within new and existing core areas, generating a strong inventory of exploration and development drilling opportunities that will allow us to meet specific production growth targets.

Two acquisitions finalized during the first quarter of 2004 enhance Kensington's growth profile. These transactions included a new core area in west-central Alberta characterized by mainly natural gas-focused, multiple-zone potential at medium drilling depths.

2003 vs. 2002

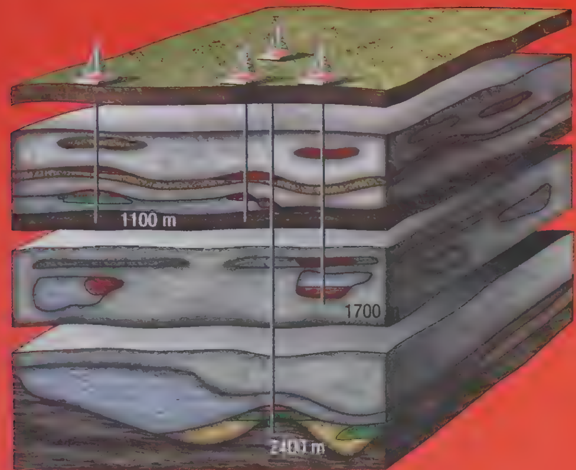
Production
2003: 820 boe per day
2002: 286 boe per day

Gross Wells Drilled
2003: 20
2002: 13

Undeveloped Land at year-end
2003: 40,163 acres
2002: 32,200 acres

Worsley

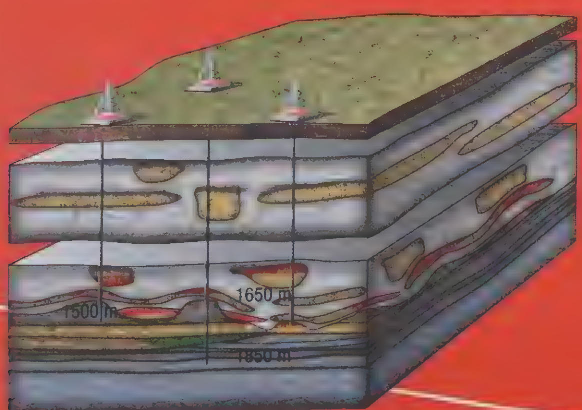
- Multiple-zone potential
- Large undeveloped land base
- Ownership in a major pipeline on prospect
- Underutilized infrastructure
- Production growth from 39 boe per day to more than 200 boe per day
- Open Crown land available for expansion



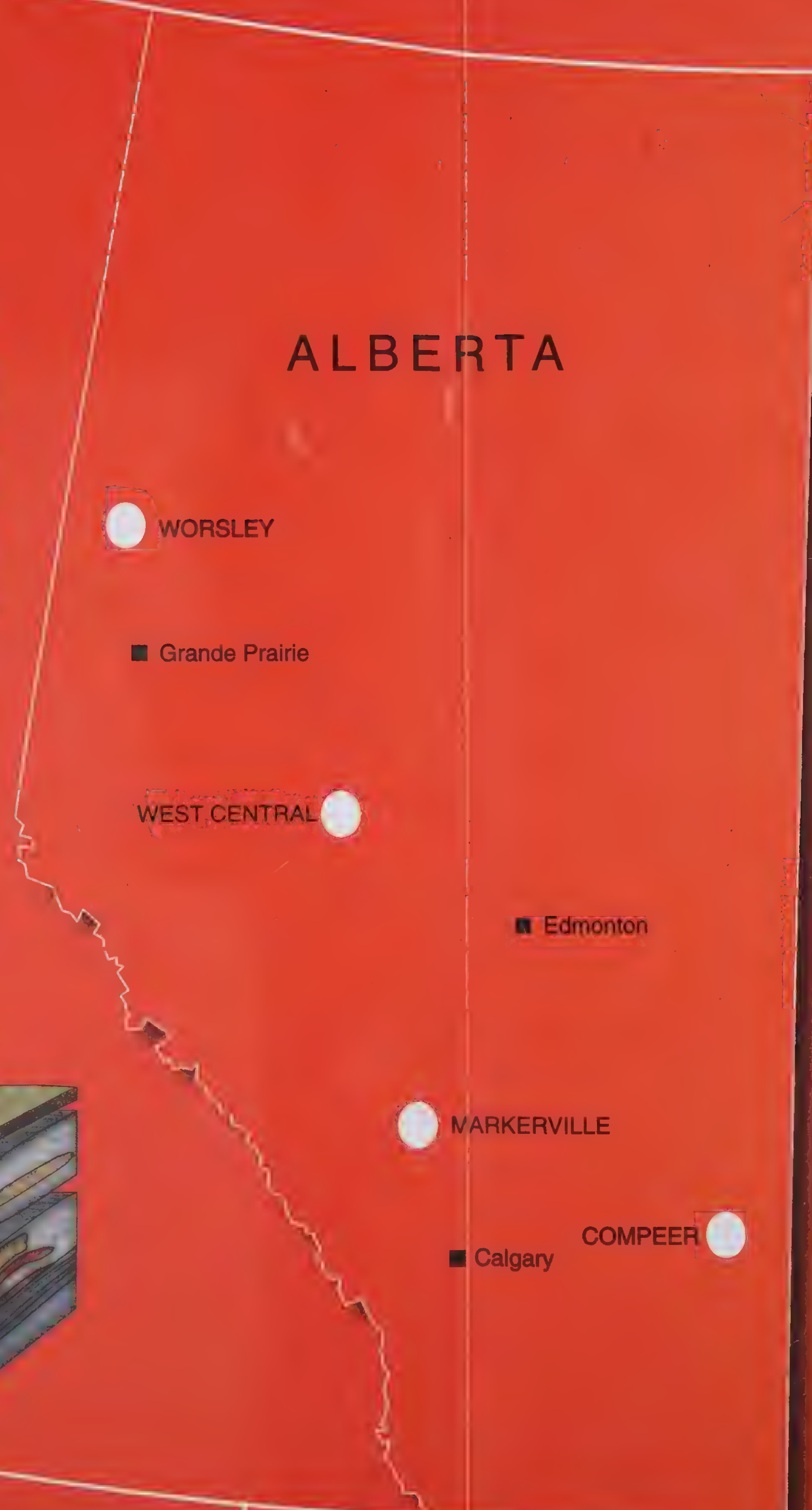
Prospective zones are stacked on structural plays in the Worsley area

West Central Area

- New core area
- Multiple-zone oil and natural gas potential
- Year-round access
- Medium drilling depths
- Open Crown land available for expansion

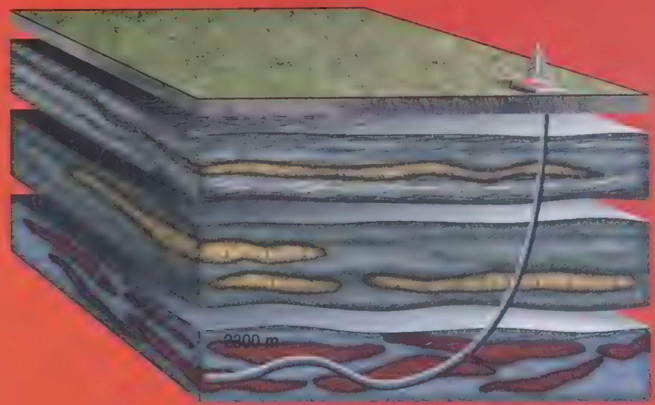


Both structural and stratigraphic plays are productive in the West Central area



Markerville

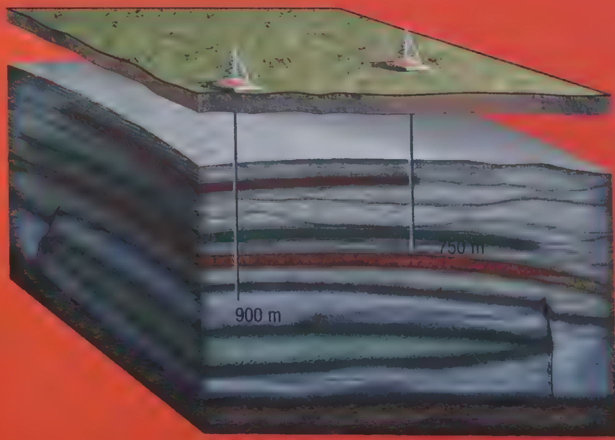
- Major Company property
- Year-round access
- 34% of the production base and 50% of year-end 2003 reserves
- Working interests of 33.75-100%
- Low decline, liquids-rich natural gas production
- Use of 3-D seismic technology is key to repeatable drilling success
- 2003 exit production of 400 boe per day



Horizontal drilling targets individual porosity units within the Pekisko formation

Compeer

- Shallow drilling depths with multi-zone potential
- Year-round access
- Working interests of 50-100%
- Pipeline ownership
- 2003 exit production of 160 boe per day



Shallow natural gas and oil production occurs on faulted salt solution structures in the Compeer area

Paul McMillan
Senior Geologist

Bryan Grams
Senior Geologist

Percy Herring
Land Manager

Rick Vigrass
Manager, Engineering

THINKING OUTSIDE THE LINES

Thinking Big

Kensington targets areas with multi-zone reservoirs for higher productivity volumes and reserves per well. Our focus is on grasping opportunities where repeatability is possible through interpretation and the presence of an available land base for expansion.

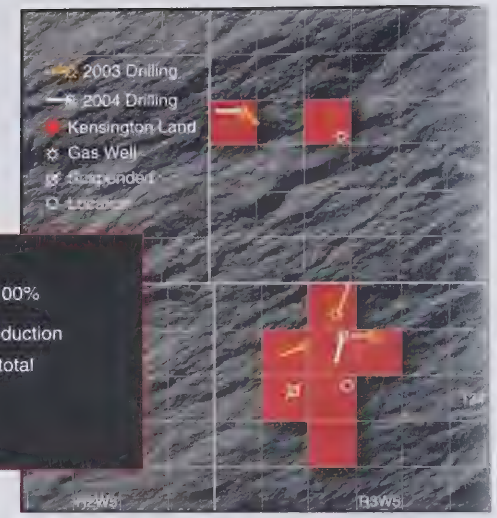
Thinking Value

Kensington incorporates 2-D and 3-D seismic information in conjunction with geological and productivity analysis to create opportunities to enhance shareholder value.

Thinking Long-term

Kensington is dedicated to growth through internally-generated prospect ideas and opportune acquisitions that establish the platform for long-term growth of the Company.

Markerville



Quick Facts

- Working interest 33.75-100%
- 400 boe per day net production – 34% of the Company total
- Year-round access
- Multiple zone potential

The Markerville Pekisko trend is a high-impact growth area with multi-zone potential and year-round access. In 2003, Kensington successfully drilled one directional and three horizontal natural gas wells, plus one unsuccessful well suspended due to drilling problems, for an 80 percent drilling success rate. The Company has working interests of 33.75-100 percent in nine sections of land. By year-end 2003 four wells were on-stream, resulting in a year end production rate of approximately 400 boe per day, representing 34 percent of the Company's total production.

At year-end 2003, the property had proved plus probable reserves of 1.3 million boe, representing 52 percent of the Company's reserve base. The Markerville asset has a reserve life index exceeding six years.

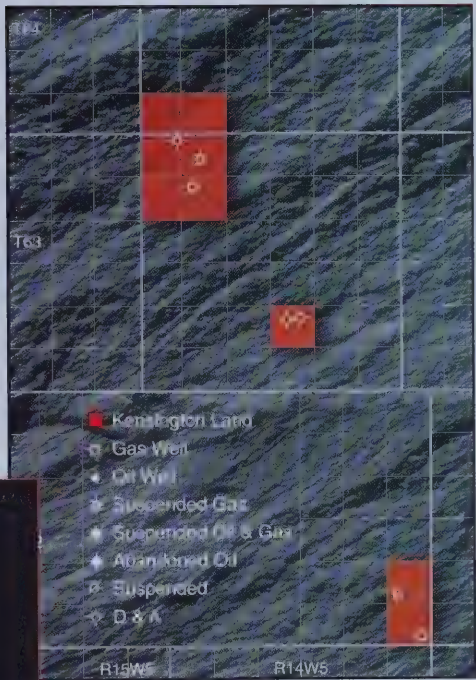
During the first quarter of 2004 Kensington drilled and completed two additional wells for Pekisko gas. One of the wells was placed on production in the first quarter. A remaining well, completed and tested, is awaiting pipeline tie-in and is expected to come on-stream by the end of the second quarter. The Company plans to drill two further wells on its Markerville lands in 2004, targeting Pekisko and Viking natural gas potential.

Kensington continues to pursue opportunities in the Markerville area through farm-in agreements, Crown and freehold land purchases and asset acquisitions. We have purchased more than 18 square kilometres of 3-D seismic data and shot a further 14 square kilometres to define drilling locations and prospects.

West Central Alberta

With the acquisition of a private company in the first quarter of 2004, a new core area has been established in west-central Alberta encompassing land holdings in the Sakwatamau, Carson Creek and Leaman regions. The year-round accessible areas have potential for oil and natural gas production from several horizons at medium drilling depths of 1,400 to 1,800 metres. Highlights of the acquisition include the addition of more than 500 boe per day of production and in excess of 11,000 net acres of undeveloped land. Kensington operates more than 90 percent of the production and infrastructure.

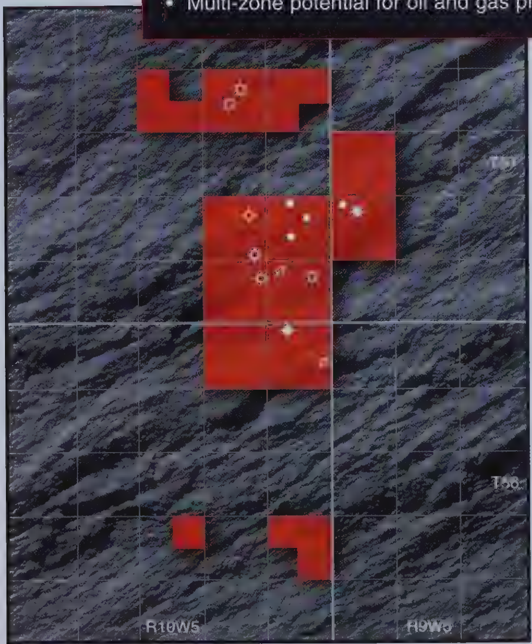
Sakwatamau



Quick Facts

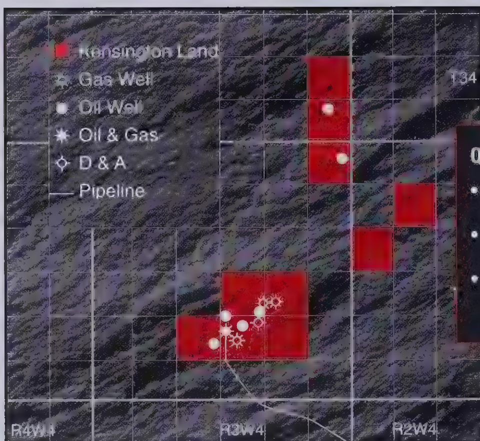
- New core area
- Medium drilling depth
- Year-round access
- 90% of production operated
- Multi-zone potential for oil and gas production

Leaman



Activities planned for 2004 and beyond include infill and step-out development drilling opportunities, compression additions and well recompletions and work-overs. We plan to take advantage of the 3-D seismic information acquired over all the prospect lands which will allow excellent repeatability of drilling locations and definition of new exploration plays. Abundant Crown lands are situated adjacent to and on trend with the prospect acreage. Acquisition of prospective land will provide the cornerstone for development of drilling opportunities and expansion within this core area.

Compeer



Quick Facts

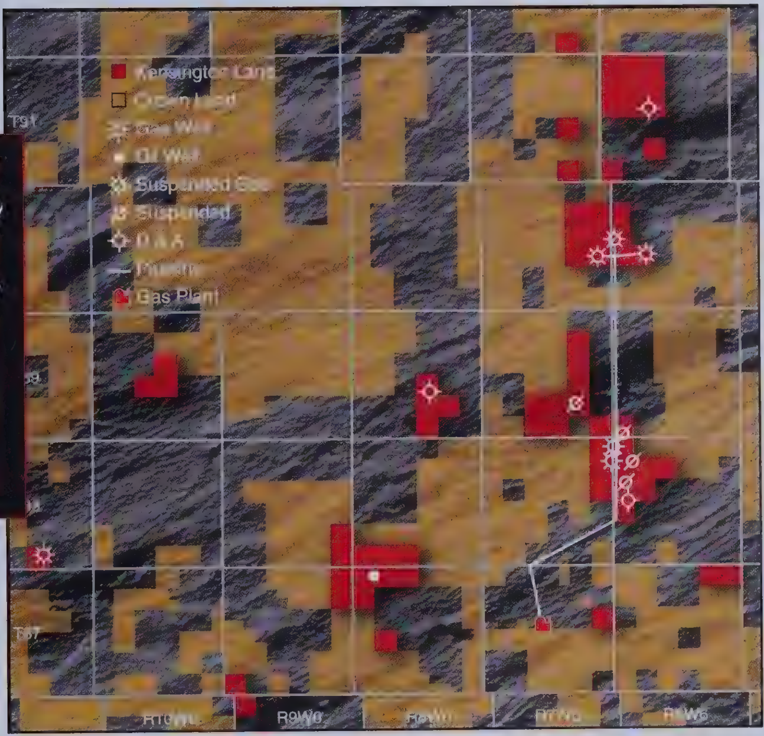
- Working interest 50-100%
- Shallow oil and natural gas production
- 180 boe per day net production – 16% of Company total

In 2003, Kensington drilled eight wells at a 100 percent success rate, resulting in two natural gas wells and six oil wells that are now on production. Production at year-end 2003 was approximately 180 boe per day, representing approximately 16 percent of total corporate production.

In 2004, Kensington's capital program on existing lands will consist of drilling one natural gas and five oil locations. We will also begin planning a waterflood recovery scheme to enhance the potential recovery and value of the developing oil pool.

The Company will continue to pursue prospects in the area through farm-in agreements and Crown land sales. A two-section pooling has been completed southwest of Compeer which has potential as a dual-zone drilling opportunity. This well is planned to be drilled in the second half of 2004.

Worsley



Quick Facts

- Highly productive oil discovery with follow-up opportunities
- Multiple zones of productivity
- Significant open Crown acreage available for growth
- Access to underutilized facilities

The Worsley prospect, located on the northern edge of the Peace River Arch, has multiple zones which are prospective for both oil and natural gas. The region carries higher exploratory risk than conventional areas. In addition, the costs to drill and operate are higher than conventional areas because of winter access conditions associated with the majority of the lands. However, as the region is emerging and relatively unexplored, it offers the potential to realize significant reserves and production through drilling and features large tracts of undeveloped land for future growth.

The Company conducted a multi-well drilling and recompletion program in its initial program in the first quarter of 2004. This resulted in four (1.6 net) wells which were placed on production and six (3.9 net) wells which were dry and abandoned. Production additions were approximately 200 boe per day net to the Company's interest, including a highly productive oil discovery with follow-up opportunities for next winter. Due to winter access conditions associated with the majority of these lands, the Company does not anticipate further drilling at Worsley until next winter.

The Company plans to shoot or acquire additional seismic to expand the opportunities on the various play trends and to take advantage of our infrastructure in the area.

Operations Statistical Review

Land

During 2003 Kensington continued to acquire highly prospective undeveloped land in key focus areas to advance its exploration and development program. The Company's gross land holdings increased by approximately 59 percent year-over-year, while net acreage grew by approximately 36 percent. More than 70 percent of the year-end land inventory was classified as undeveloped, creating a solid platform to support growth-oriented exploration and development activities. The Company's working interest in its land holdings declined from 67 percent in 2002 to 57 percent in 2003. This resulted from increased joint venture participation with other companies to access their lands, as well as a reflection of our lower working interest position acquired at Worsley in 2003.

Land Holdings

(acres)	2003			2002		
	Gross	Net	Average W.I. %	Gross	Net	Average W.I.%
Developed	**29,140**	**16,801**	**58**	15,372	9,767	64
Undeveloped	**71,122**	**40,163**	**56**	47,580	32,200	68
Total	**100,262**	**56,964**	**57**	62,952	41,967	67

Undeveloped Land Reconciliation

(acres)	Gross	Net
December 31, 2002	47,580	32,200
Acquisitions (land sales and farm-ins)	42,595	20,413
Dispositions	(4,640)	(2,175)
Expiries and reallocations to developed	(14,413)	(10,275)
December 31, 2003	**71,122**	**40,163**

Drilling Activity

Drilling activity reached record levels in 2003. Kensington drilled 20 wells (14.5 net) and achieved a 96 percent success rate. The Company focused more than half of its drilling operations in the key areas of Markerville and Compeer in central Alberta, generating large increases in production and reserves during the year.

The Company operated 70 percent of its drilling. The average working interest of new wells drilled in 2003 was 73 percent. Forty percent of the Company's drilling operations were conducted at exploratory locations.

Kensington operated four of the six wells drilled at Markerville during 2003, targeting the Pekisko Formation at 2,300 metres total vertical depth using horizontal drilling. The drilling program resulted in five (3.0 net) natural gas wells and one (0.38 net) well which was incapable of production due to hole difficulties. Three of the wells were placed on production in 2003. A fourth well was tied in during the first quarter of 2004, and the fifth well (non-operated) is awaiting tie-in.

At Compeer, the Company drilled eight wells (8.0 net) at a 100 percent success rate targeting the relatively shallow Mannville, Belly River and Colony formations at depths of less than 900 metres. During the year the Company placed six of its wells on production, including two Mannville natural gas wells, one Belly River natural gas well and three of the Colony oil wells that it drilled. Further drilling and tie-in of the Company's remaining Colony oil wells occurred during the first quarter of 2004.

Other areas drilled by the Company in 2003 included Iron Springs in southern Alberta, where two wells (2.0 net) were drilled and cased for shallow gas potential. At Dyberg, in central Alberta, one well (0.25 net) was drilled as a Mannville natural gas well, while at Fir in west-central Alberta, one well (0.3 net) was drilled as a Cadomin natural gas well. Finally, at the minor areas of Legal and Kitty, two non-operated wells (0.6 net) were both dry and abandoned.

Drilling Activity

(wells)	**2003**		2002		2001	
	Gross	Net	Gross	Net	Gross	Net1
Oil	**6**	**6.0**	3	1.9	1	1.0
Natural gas	**12**	**7.9**	8	6.4	1	1.0
Standing	**0**	**–**	0	–	2	0.4
Dry	**2**	**0.6**	2	2.0	0	–
Total	**20**	**14.5**	13	10.3	4	2.4
Exploratory	**8**	**5.9**	9	7.4	2	0.4
Development	**12**	**8.6**	4	2.9	2	2.0
Average working interest	**–**	**73**	–	79	–	60
Success rate (%)	**–**	**96**	–	81	–	100

Report on Reserves Data by Independent Qualified Reserves Evaluator

To the Board of Directors of Kensington Energy Ltd:

1. We have prepared an evaluation of the Company's reserves data as at December 31, 2003. The reserves data consist of the following:
   - (a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2003, using forecast prices and costs; and
     - (ii) the related estimated future net revenue; and
   - (b) (i) proved oil and gas reserves estimated as at December 31, 2003, using constant prices and costs; and
     - (ii) the related estimated future net revenue.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the COGE Handbook) prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2003, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's Board of Directors:

		Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – $M)			
Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Audited	Evaluated	Reviewed	Total
February 27, 2004	Canada	–	26,974	–	26,974

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook.

6. We have no responsibility to update this evaluation for events and circumstances occurring after the preparation dates.

7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

"SIGNED"

Myron J. Hladyshevsky, P. Eng.

Gilbert Laustsen Jung Associates Ltd., Calgary, Alberta, Canada

Dated February 27, 2004

Reserves

Kensington's corporate reserves report was prepared by the independent engineering firm Gilbert Laustsen Jung Associates Ltd. (GLJ) in 2003 and in prior years by Martin & Brusset Associates. The Company's reserves disclosure has changed significantly this year, as it has for all other reporting issuers, due to a regulatory initiative. Under a new instrument, National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities (NI 51-101), probable reserves are now risked before they are disclosed. This is a change from previous years where probables were disclosed unrisked, then reduced by 50 percent and reported as a portion of established reserves. Established (proved plus half probable) reserves presented in 2002 and prior years are considered to be a reasonable estimate of the reserves that would actually be recovered and are comparable to the proved plus probable reserves reported under NI 51-101 for 2003. For that reason, and for the purposes of this report, the established reserves category from prior years is considered equivalent to the current proved plus probable (P+P) category. Under NI 51-101 there is a 90 percent probability that actual reserves will equal or exceed reported proved reserves. In previous years this probability was 80 percent.

Kensington's proved reserves showed a marked increase over 2002. The Company's proved reserves at year-end 2003 were 2.0 million boe, an increase of 70 percent from 1.2 million boe at year-end 2002. The Company's exploration program was very successful in converting probable reserves to proved, primarily at Markerville and Compeer.

Proved plus probable reserves at year-end 2003 were 2.5 million boe, which was 2 percent higher than the 2.4 million boe of established reserves in 2002. While reserves increased due to exploration success at Markerville and Compeer, the magnitude of this increase was reduced due to the implementation of NI 51-101. Certain of the Company's probable reserves recognized at year-end 2002, located primarily at Markerville, were converted into proved reserves by year-end 2003 due to the Company's successful drilling program. This conversion of probable reserves to proved reserves resulted in no net increase in proved plus probable reserves.

Company Interest Summary of Reserves – Forecast Prices and Costs

December 31,	Crude Oil (mbbls)	Natural Gas Liquids (mbbls)	Natural Gas (mmcf)	2003 Total (mboe)	2002 Total (mboe)
Proved					
Developed producing	116	269	7,411	**1,620**	926
Developed non-producing	103	62	1,121	**352**	227
Undeveloped	–	–	375	**63**	46
Total proved	220	330	8,907	**2,035**	1,199
Probable [1]	116	62	1,668	**456**	1,236
Total proved plus probable [2]	336	393	10,575	**2,491**	2,435

Note: May not add due to rounding

(1) Represents risked reserves for 2002

(2) Represents established reserves for 2002

Company Interest Before Tax Net Present Value of Reserves – Forecast Prices and Costs

December 31, 2003 ($ thousands)	Undiscounted	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Proved					
Developed producing	27,829	22,231	19,050	16,946	15,415
Developed non-producing	5,605	4,495	3,778	3,272	2,897
Undeveloped	721	614	533	469	419
Total proved	34,154	27,340	23,360	20,687	18,731
Probable	6,896	4,685	3,614	2,948	2,482
Total proved plus probable	41,050	32,025	26,974	23,635	21,213

Note: May not add due to rounding

Pricing Assumptions – Forecast Prices and Costs

The January 1, 2004 pricing forecast presented below has been prepared by GLJ. These prices have been used in determining the reserves and cash flow forecasts above.

Year	Crude Oil WTI (US$/bbl)	Crude Oil Edmonton Light (Cdn$/bbl)	Natural Gas AECO (Cdn$/mmbtu)	Natural Gas Sumas Spot (US$/mmbtu)	Inflation Rate (%/year)
2004	29.00	37.75	5.85	4.55	1.5
2005	26.00	33.75	5.15	4.00	1.5
2006	25.00	32.50	5.00	3.90	1.5
2007	25.00	32.50	5.00	3.90	1.5
2008	25.00	32.50	5.00	3.90	1.5
2009	25.00	32.50	5.00	3.90	1.5
2010	25.00	32.50	5.00	3.90	1.5
2011	25.00	32.50	5.00	3.90	1.5
2012	25.00	32.50	5.00	3.90	1.5
2013	25.00	32.50	5.00	3.90	1.5
2014	25.00	32.50	5.00	3.90	1.5
Thereafter	+1.5%/yr	+1.5%/yr	+1.5%/yr	+1.5%/yr	1.5

Company Interest Before Tax Net Present Value of Reserves – Constant Prices and Costs

($ thousands)	Undiscounted	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Proved					
Developed producing	35,100	27,724	23,494	20,689	18,653
Developed non-producing	7,405	5,844	4,835	4,133	3,620
Undeveloped	1,041	875	751	655	580
Total proved	43,547	34,443	29,080	25,477	22,852
Probable	8,979	6,241	4,828	3,931	3,301
Total proved plus probable	52,526	40,684	33,908	29,408	26,154

Note: May not add due to rounding

Pricing Assumptions – Constant Prices and Costs

Year	Crude Oil WTI (US$/bbl)	Crude Oil Edmonton Light (Cdn$/bbl)	Natural Gas AECO (Cdn$/mmbtu)	Natural Gas Sumas Spot (US$/mmbtu)	Inflation Rate (%/year)
2004	32.52	40.81	6.09	5.49	–

Reserves Reconciliation

Reconciliation of Company Gross[1] Reserves by Principal Product Type – Forecast Prices and Costs

	Crude Oil (mbbls)	Natural Gas Liquids (mbbls)	Natural Gas (mmcf)	Total (mboe)
Proved Producing				
December 31, 2001	195	50	2,256	621
Discoveries and extensions	–	–	715	119
Technical revisions	18	(37)	(531)	(108)
Acquisitions	32	43	1,933	397
Dispositions	–	–	–	–
Production	(32)	(9)	(383)	(104)
December 31, 2002	214	47	3,988	926
Exploration discoveries	39	5	400	110
Drilling extensions	36	204	4,290	955
Improved recovery	–	14	920	167
Technical revisions	34	38	(824)	(65)
Acquisitions	–	–	200	33
Dispositions	(180)	(1)	(160)	(208)
Production	(27)	(39)	(1,398)	(299)
December 31, 2003	**116**	**269**	**7,411**	**1,620**
Total Proved				
December 31, 2001	219	65	3,014	786
Discoveries and extensions	47	4	2,077	397
Technical revisions	(6)	(56)	(1,295)	(278)
Acquisitions	32	43	1,933	397
Dispositions	–	–	–	–
Production	(32)	(9)	(383)	(104)
December 31, 2002	260	47	5,350	1,199
Exploration discoveries	39	5	400	110
Drilling extensions	66	265	5,400	1,230
Improved recovery	1	14	920	168
Technical revisions	62	38	(1,965)	(228)
Acquisitions	–	–	360	60
Dispositions	(180)	(1)	(160)	(208)
Production	(27)	(39)	(1,398)	(299)
December 31, 2003	**220**	**330**	**8,907**	**2,035**

	Crude Oil (mbbls)	Natural Gas Liquids (mbbls)	Natural Gas (mmcf)	Total (mboe)
Probable [2]				
December 31, 2001	37	9	682	159
Discoveries and extensions	69	91	3,330	715
Technical revisions	51	(6)	(377)	(18)
Acquisitions	4	80	1,771	379
Dispositions	–	–	–	–
Production	–	–	–	–
December 31, 2002	161	174	5,405	1,236
Exploration discoveries	24	1	300	75
Drilling extensions	14	(184)	(3,262)	(714)
Improved recovery	–	1	100	18
Technical revisions	101	75	(225)	139
Acquisitions	–	–	60	10
Dispositions	(184)	(5)	(710)	(307)
Production	–	–	–	–
December 31, 2003	**116**	**62**	**1,668**	**456**
Proved plus Probable [3]				
December 31, 2001	256	74	3,696	945
Discoveries and extensions	116	95	5,407	1,112
Technical revisions	45	(62)	(1,669)	(294)
Acquisitions	36	123	3,704	776
Dispositions	–	–	–	–
Production	(32)	(9)	(383)	(104)
December 31, 2002	421	221	10,755	2,435
Exploration discoveries	63	6	700	186
Drilling extensions	80	81	2,138	517
Improved recovery	1	15	1,020	186
Technical revisions	163	114	(2,190)	(88)
Acquisitions	–	–	420	70
Dispositions	(364)	(6)	(870)	(515)
Production	(27)	(39)	(1,398)	(299)
December 31, 2003	**336**	**393**	**10,575**	**2,491**

Note: May not add due to rounding

(1) Gross reserves represent the Company's interest before deducting royalties

(2) Represents risked reserves for 2002

(3) Represents established reserves for 2002

Capital Expenditures

($)	2003	2002
Land	964,651	1,073,427
Drilling and completions	10,186,717	3,915,021
Property acquisitions	–	2,872,794
Production facilities	3,108,116	1,036,900
Geological and geophysical (seismic)	1,818,375	894,805
Capital expenditures without A&D	16,077,859	6,920,153
Property acquisitions	1,175,380	2,872,794
Property dispositions	(3,947,686)	–
Capital expenditures with A&D	13,305,553	9,792,947
Computer equipment and furniture	65,259	80,059
Total capital expenditures	13,370,812	9,873,006

The Company invested a total of $13.4 million during 2003, another consecutive year of record exploration activity. Approximately $10.2 million was used to fund the Company's drilling program of 14.5 net wells. The Company sold its interest at Giroux Lake for $3.9 million and redeployed the capital into higher growth opportunities focused on natural gas. The Company also completed $1.2 million of acquisitions, the most significant of which was Worsley, a new exploration area with significant undeveloped land.

Finding and Development Costs (F&D) and Finding, Development and Net Acquisition Costs (FD&A)

Finding and development costs associated with the 2003 exploration and development program, including revisions and the change in future capital, were $12.81 per proved boe and $17.90 per proved plus probable boe.

Finding, development and acquisition costs associated with the 2003 capital program, including revisions and the change in future capital, were $12.04 per proved boe and $32.48 per proved plus probable boe. The proved plus probable value is large and non-representative due to the disposition in 2003 of significant probable reserves (the natural gas cap on the Giroux Lake oil pool) that were heavily discounted in value as they were not forecast to be placed on production until 2014. This value was additionally affected by the conversion of probable reserves recognized at year-end 2002, located primarily at Markerville, into proved reserves at year-end 2003 by the Company's drilling program with a slight increase in proved plus probable reserves.

Proved	2003 Capital Expenditures ($ thousands)	2003 Reserves Additions (mboe)	2003 ($/boe)	2002 Capital Expenditures ($ thousands)	2002 Reserves Additions (mboe)	2002 ($/boe)
F&D						
Exploration and development program before revisions	16,078	1,508	10.66	6,920	397	17.43
Exploration and development program after revisions (a)	16,078	1,280	12.56	6,920	162	42.72
Exploration and development program including change in future capital (b)	16,400	1,280	12.81	6,992	162	43.16
Net acquisition/disposition activity (c)	(2,772)	(148)	18.73	2,873	354	8.12
FD&A						
Before change in future development costs (a+c)	13,306	1,132	11.75	9,793	516	18.98
Including change in future development costs (b+c)	13,628	1,132	12.04	9,865	516	19.12

Proved plus Probable*	2003 Capital Expenditures ($ thousands)	2003 Reserves Additions (mboe)	2003 ($/boe)	2002 Capital Expenditures ($ thousands)	2002 Reserves Additions (mboe)	2002 ($/boe)
F&D						
Exploration and development program before revisions	16,078	889	18.09	6,920	1,112	6.22
Exploration and development program after revisions (a)	16,078	801	20.07	6,920	860	8.05
Exploration and development program including change in future capital (b)	14,335	801	17.90	10,005	860	11.63
Net acquisition/disposition activity (c)	(2,772)	(445)	6.23	2,873	734	3.91
FD&A						
Before change in future development costs (a+c)	13,306	356	37.38	9,793	1,594	6.14
Including change in future development costs (b+c)	11,563	356	32.48	12,878	1,594	8.08

** Represents established reserves for 2002*

Reconciliation of Changes in Future Development Capital

When calculating the change in future development capital costs to develop proved plus probable reserves, the change in definition of the proved plus probable reserves category in 2003 compared to 2002 must be kept in mind. For proved plus probable reserves we have compared the 2003 future development costs with the 2002 future development costs to develop established reserves as these are more comparable.

Reconciliation of Changes in Future Development Capital

($ thousands)		Proved	Change	Proved plus Probable	Change
2003		**632**		**1,642**	
	Change from 2002-2003		**322**		**(1,743)**
2002		310		3,385	
	Change from 2001-2002		72		3,085
2001		238		300	

Three year Average F&D – 2001-2003

	Proved			Proved Plus Probable*		
	Capital Expenditures ($ thousands)	Reserves Additions (mboe)	($/boe)	Capital Expenditures ($ thousands)	Reserves Additions (mboe)	($/boe)
F&D						
Exploration and development program before revisions	25,051	2,320	10.80	25,051	2,416	10.37
Exploration and development program after revisions (a)	25,051	1,764	14.20	25,051	1,279	19.59
Exploration and development program including change in future capital (b)	25,486	1,764	14.45	25,312	1,279	19.79
Net acquisition/disposition activity (c)	(149)	252	(0.59)	(149)	416	(0.36)
FD&A						
Before change in future development costs (a+c)	24,901	2,016	12.35	24,901	1,695	14.69
Including change in future development costs (b+c)	25,336	2,016	12.57	25,162	1,695	14.85

** Represents established reserves for 2001 and 2002*

Reserve Life Index

The Company's proved reserve life index (RLI) using annualized fourth-quarter production is 4.9 years for proved reserves and 5.9 years for proved plus probable reserves. The reserve life index of 8.5 years at year-end 2002 reflected a component of proved non-producing reserves which were subsequently brought onstream in early 2003.

	2003 Using Annualized Q4 Production	2003 Using Average Production	2002 Using Annualized Q4 Production	2002 Using Average Production
Production (boe/d)	**1,148**	**820**	388	286
Proved reserves (mboe)	**2,035**	**2,035**	1,199	1,199
Proved reserve life index (years)	**4.9**	**6.8**	8.5	11.5
Proved plus probable reserves (mboe)*	**2,491**	**2,491**	2,435	2,435
Proved plus probable reserve life index (years)*	**5.9**	**8.3**	17.2	23.3

** Represents established reserves for 2002*

Reserves Replacement

The Company's 2003 capital investment program replaced production by a factor of 4.3 times on a proved basis and 2.7 times on a proved plus probable basis.

	2003	2002
Production (boe/d)	820	286
Proved reserve additions after revisions (mboe)	1,280	162
Proved replacement ratio	4.3	1.6
Proved plus probable reserve additions after revisions (mboe)*	801	860
Proved plus probable replacement ratio	2.7	8.2

** Represents established reserves for 2002*

Recycle Ratio

The recycle ratio is a measure for evaluating the effectiveness of a company's re-investment program. The ratio measures the efficiency of capital investment. It accomplishes this by comparing the operating netback per barrel of oil equivalent to that year's reserve finding and development costs.

	2003	2002
Operating netback ($/boe)	22.82	21.39
Proved finding and development costs after revisions and including the change in future development costs ($/boe)	12.81	43.16
Proved recycle ratio (F&D)	1.8	0.5
Proved finding, development and acquisition costs after revisions and including the change in future development costs ($/boe)	12.04	19.12
Proved recycle ratio (FD&A)	1.9	1.1

Net Asset Value

($)	Undiscounted	Discounted at 5%	Discounted at 10%	Discounted at 15%
Net present value of reserves*	41,050,000	32,025,000	26,974,000	23,635,000
Value of land and seismic**	3,591,540	3,591,540	3,591,540	3,591,540
Working capital***	3,361,160	3,361,160	3,361,160	3,361,160
Bank debt	–	–	–	–
Stock option proceeds	1,606,740	1,606,740	1,606,740	1,606,740
Total net asset value diluted	49,609,440	40,584,440	35,533,440	32,194,440
Year-end diluted shares	52,020,749	52,020,749	52,020,749	52,020,749
Net asset value diluted ($ per share)	0.95	0.78	0.68	0.62

**Based on proved plus probable reserves at forecast prices and costs*

***Based on undeveloped land at $75/acre*

****Excluding bank debt*

Management's Discussion and Analysis

Management's discussion and analysis (MD&A) of the results of operations for the year ended December 31, 2003 should be read in conjunction with the audited financial statements and the notes to the financial statements for the years ended December 31, 2003 and 2002.

Where amounts are expressed on a barrel of oil equivalent basis (boe), natural gas volumes have been converted to barrels of oil at six thousand cubic feet (mcf) per barrel (bbl). This conversion conforms with the Canadian Securities Administrators' National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities (NI 51-101). Boe figures may be misleading, particularly if used in isolation. A boe conversion of six thousand cubic feet per barrel is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Cash flow from operations, as used in this MD&A, is not defined under Generally Accepted Accounting Principles (GAAP). The reconciliation between net income and cash flow from operations can be found in the statements of cash flows in the audited financial statements. Cash flow from operations per share is calculated using the weighted average shares outstanding consistent with the calculation of net income per share.

This disclosure contains certain forward-looking statements that involve substantial known and unknown risks and uncertainties, certain of which are beyond Kensington's control, including: the impact of general economic conditions in Canada and the United States; industry conditions; changes in laws and regulations including the adoption of new environmental laws and regulations and changes in how they are interpreted and enforced; increased competition; the lack of availability of qualified personnel or management; fluctuations in foreign exchange or interest rates; stock market volatility and market valuations of companies with respect to announced transactions and the final valuations thereof; and obtaining required approvals of regulatory authorities. Kensington's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurances can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits, including the amount of proceeds, that Kensington will derive therefrom.

2003 Overview

Kensington reported strong growth in production, revenue, net income and cash flow on both an absolute basis and a per share basis. Production volume growth of 187 percent was the most significant factor in Kensington's results. The industry and Kensington have benefited from high energy prices over the last two years. Investors looked favorably to junior E&P companies that were able to show growth. As a result of market support, Kensington completed two equity financings, the first in March 2003 and the second in November 2003, that raised gross proceeds of $16 million. During 2003, the Company made property acquisitions totalling $1.2 million, which consisted mainly of lands in the Worsley area. In July 2003 the Company disposed of a mature oil producing property at Giroux Lake for approximately $3.9 million.

Significant Accounting Policies

Basis of Presentation

The financial data presented has been prepared in accordance with Canadian GAAP.

Measurement Uncertainty

The amounts recorded for depletion and depreciation of property and equipment and the provision for future site restoration costs and the ceiling test calculation are based on estimates of proved reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect of changes in such estimates on the financial statements in future periods could be significant.

Changes in Accounting Policies

Stock-Based Compensation Plan

Under the Company's stock option plan, options to purchase common shares are granted to directors, officers and employees at current market prices. Effective January 1, 2003, the Company adopted the recommendations of the Canadian Institute of Chartered Accountants (CICA) on accounting for stock-based compensation. As permitted by this new pronouncement, the Company prospectively adopted the fair value method of accounting for stock options granted to employees and directors. Stock-based compensation is recorded in the statement of

income as general and administrative expense for all options granted on or after January 1, 2003, with a corresponding increase recorded as contributed surplus. Compensation expense for options is based on the estimated fair values at the time of the grant and the expense is recognized over the vesting period of the option.

Flow-Through Shares

In 2003, the Company prospectively adopted the recommendation of the Emerging Issues Committee of the CICA on flow-through shares, which requires the recognition of the foregone tax benefits at the time of renouncement provided there is reasonable assurance that the expenditures will be incurred. Prior to 2003, the tax effect of the renouncement was recorded when the corresponding exploratory and development expenditures were incurred.

Recent Accounting Pronouncements Issued

Asset Retirement Obligations

In March 2003, the CICA approved Section 3110, "Asset Retirement Obligations", which requires liability recognition for retirement obligations associated with the Company's property, plant and equipment. The obligations are initially measured at fair value, which is the discounted future value of the liability. The fair value is capitalized as part of the cost of the related assets and amortized to expense over their useful lives. The liability accretes until the retirement obligations are settled. Section 3110 is effective for fiscal years beginning on or after January 1, 2004. The site restoration liability currently on the balance sheets, which has been calculated using the unit-of-production method, will be reversed on January 1, 2004. The Company is currently evaluating the impact of this standard on its financial statements.

Petroleum and Natural Gas Assets – Full Cost Accounting

In September 2003, the CICA issued Accounting Guideline 16, "Oil and Gas Accounting – Full Cost" (AcG16), to replace AcG5. The new guideline is effective for fiscal years beginning on or after January 1, 2004. The most significant change between AcG16 and AcG5 is that AcG-16 limits the carrying value of petroleum and natural gas properties to their fair value. The fair value is equal to estimated future cash flows from proved and probable reserves using future price

Operating Margin Analysis

	2003	2002	% Change
Production			
Oil and NGLs (bbls/d)	182	111	64
Natural gas (mcf/d)	3,829	1,050	265
Oil equivalent (boe/d)	820	286	187
Average prices			
Oil and NGLs ($/bbl)	35.36	37.04	(5)
Natural gas ($/mcf)	6.20	4.59	35
Oil equivalent ($/boe)	36.79	31.24	18
Dollars			
Petroleum and natural gas revenue	11,007,410	3,258,923	238
Royalties (net of ARTC)	2,495,103	541,585	361
Production costs	1,684,973	486,004	247
Operating netback	6,827,334	2,231,334	206
General and administrative – excluding stock-based compensation	1,206,762	711,792	70
Capital taxes	44,350	13,736	223
Interest and other income (expense)	(19,796)	7,449	–
Cash flow from operations	5,556,426	1,513,255	267
Depletion, depreciation and site restoration	3,482,520	1,187,240	193
Stock-based compensation	161,459	–	–
Future income taxes	190,200	130,336	46
Net income	1,722,247	195,679	780
$ per boe			
Petroleum and natural gas revenue	36.79	31.24	18
Royalties (net of ARTC)	8.34	5.19	61
Production costs	5.63	4.66	21
Operating netback	22.82	21.39	7
General and administrative – excluding stock-based compensation	4.03	6.82	(41)
Capital taxes	0.15	0.13	15
Interest and other income (expense)	(0.07)	0.07	–
Cash flow from operations	18.57	14.51	28
Depletion, depreciation and site restoration	11.64	11.38	2
Stock-based compensation	0.54	–	–
Future income taxes	0.64	1.25	(49)
Net income	5.75	1.88	205
Margins (%)			
Petroleum and natural gas revenue	100.0	100.0	
Royalties (net of ARTC)	22.7	16.6	37
Production costs	15.3	14.9	3
Operating netback	62.0	68.5	(9)
General and administrative – excluding stock-based compensation	11.0	21.9	(50)
Capital taxes	0.4	0.4	(5)
Interest and other income (expense)	(0.2)	0.2	–
Cash flow from operations	50.4	46.4	9
Depletion, depreciation and site restoration	31.6	36.4	(13)
Stock-based compensation	1.5	–	–
Future income taxes	1.7	4.0	(57)
Net income	15.6	6.0	159

forecasts and costs discounted at a risk-free rate. This differs from the current cost recovery ceiling test under AcG5 that uses undiscounted cash flows and constant prices, less general and administrative, financing costs and income tax expense. The Company is following AcG5 at December 31, 2003. AcG16 also adopted the reserves evaluation and disclosure requirements of NI 51-101, which has been followed in the preparation of this report. The Company is currently evaluating the impact of this standard on its financial statements.

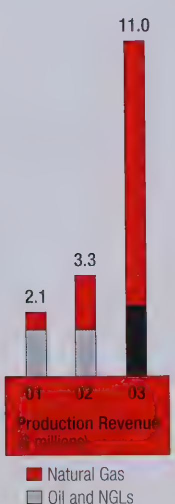
Production Volumes

In 2003 average production increased to 820 boe per day from 286 boe per day in 2002. Natural gas production increased by 265 percent during the year to 3,829 mcf per day from 1,050 mcf per day in 2002. Oil and natural gas liquids production increased to 182 barrels per day in 2003 from 111 barrels per day in 2002. The increase in oil and natural gas liquids production is net of the disposition of the Giroux Lake properties on July 15, 2003 which produced approximately 100 barrels per day of oil.

In 2003, 78 percent of Kensington's production was from natural gas compared to 61 percent in 2002. After the disposition of the Giroux Lake properties less than 5 percent of Kensington's production is oil.

Production Revenue

For the year ended December 31, 2003 petroleum and natural gas sales were $11,007,410, an increase of 238 percent from $3,258,923 in 2002. The increase in petroleum and natural gas sales experienced by Kensington is primarily due to an increase in natural gas and natural gas liquids volumes supported by increasing natural gas prices.



In 2003, natural gas prices averaged $6.20 per mcf compared to $4.59 per mcf in 2002, while oil and natural gas liquids prices averaged $35.36 per barrel compared to $37.04 in 2002.

Kensington did not hedge any of its production in 2003 or 2002 and has no hedges in place relating to future period production.

Royalties

Total royalties, net of Alberta Royalty Tax Credit, for the year ended December 31, 2003 were $2,495,103, for an average royalty rate of 23 percent, compared to $541,585 with an average royalty rate of 17 percent for the same period in 2002. The increase in royalties is a result of increased petroleum and natural gas sales in these periods. The increase in the royalty rate is due to the Company's production mix shifting to high volume natural gas wells that attract a higher royalty rate, an increase in gross overriding royalties on farm-in lands and a lower proportion of Crown royalties and associated Alberta Royalty Tax Credit.

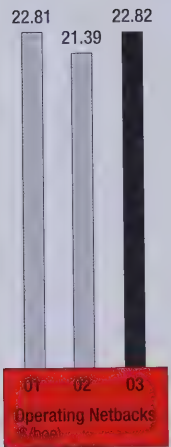
Production Expenses

For the year ended December 31, 2003 production expenses were $1,684,973 or $5.63 per boe, an increase from $486,004 or $4.66 per boe in 2002. Production expenses were relatively constant in 2003 from quarter-to-quarter, but were higher than in 2002 due to the increase in natural gas processing fees associated with the greater use of third-party facilities.

General and Administrative Expenses

($)	2003	2002
Gross cash G&A expenses	1,885,092	1,186,334
Overhead recoveries	(322,693)	(113,088)
Salaries and direct costs capitalized	(385,627)	(386,454)
Net cash G&A expenses	1,206,762	711,792
Per boe	4.03	6.82
Non-cash stock-based compensation	161,459	–
Total net G&A expenses	1,368,221	711,792
Per boe	4.57	6.82

In 2003 general and administration expenses (G&A), excluding stock-based compensation, were $1,206,762, an increase from $711,792 in 2002. G&A increased in 2003 as a result of increased staffing to accommodate the Company's higher activity levels. At year-end 2003 Kensington had 14 full-time head-office staff. On a boe basis, the fourth-quarter G&A, excluding stock-based compensation, declined to $2.12 per boe while 2003 G&A declined by 41 percent from 2002. The improvements on a per boe basis reflect the increase in the Company's production levels. The Company's overhead recoveries are a function of the number of properties operated by the



Company and its operated capital program. The Company capitalizes the salaries and associated direct costs of professional staff directly associated with the Company's exploration and development activities. The Company does not capitalize indirect overhead.

In 2003 the Company adopted the recommendations of the CICA on accounting for stock-based compensation. The effect of this was to record compensation expense of $161,459 for options granted in 2003 in general and administrative expenses in 2003.

Interest Expense

In 2003 interest expense was $49,967 compared to $20,782 in 2002. The increase in interest reflects the debt level of Kensington during the first quarter of 2003 prior to the March 27, 2003 equity private placement.

Capital And Income Taxes

Capital taxes were $44,350 in 2003 compared to $13,736 in 2002. The increase in capital taxes is due to the increase in the size of the Company as a result of equity financings in 2003.

For the year ended December 31, 2003 the provision for future income taxes was $190,200 compared to $130,336 in 2002. Included in the 2003 provision is a benefit of $515,000 related to substantively enacted changes to the provincial and federal income tax rates.

There was no cash income tax provision in 2003 and none is expected in 2004. At December 31, 2003 the Company had the following tax pool balances:

Tax Pools at December 31, 2003

($)	
Canadian oil and gas property expense (COGPE)	1,744,000
Canadian development expense (CDE)	5,774,000
Canadian exploration expense (CEE)	5,626,000
Undepreciated capital costs (UCC)	3,851,000
Total	16,995,000

Depletion, Depreciation and Site Restoration

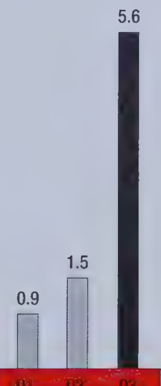
Depletion, depreciation and site restoration charges, calculated on a unit-of-production method, are based on total proved reserves. The 2003 depletion calculation includes $628,000 of future capital expenditures to develop the Company's proved reserves, but excludes $2,809,062 of unproved properties.

For the year ended December 31, 2003 depletion and depreciation increased to $3,400,020 from $1,154,140 for 2002. The provision for site restoration and abandonment was $82,500 for the year ended December 31, 2003 compared to $33,100 for 2002.

On a unit-of-production basis, depletion, depreciation and site restoration were $11.64 per boe for the year ended December 31, 2003 versus $11.38 per boe for 2002.

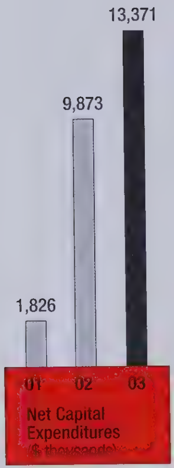
Net Income and Cash Flow from Operations

For the year ended December 31, 2003 net income was $1,722,247 compared to $195,679 for 2002. For the year ended December 31, 2003 cash flow increased to $5,556,426 from $1,513,255 in 2002.



Cash Flow from Operations ($ millions)

The increase in net earnings and cash flow from operations in 2003 from 2002 resulted primarily from significantly higher production of natural gas and natural gas liquids and higher natural gas prices being received in 2003.



Capital Expenditures

Kensington's net capital expenditures for the year ended December 31, 2003 and 2002 are as follows:

($)	2003	2002
Land	964,651	1,073,427
Drilling and completions	10,186,717	3,915,021
Property acquisitions	1,175,380	2,872,794
Property dispositions	(3,947,686)	–
Production facilities	3,108,116	1,036,900
Geological and geophysical (seismic)	1,818,375	894,805
Computer equipment and furniture	65,259	80,059
Total capital expenditures	13,370,812	9,873,006

Capital expenditures, net of dispositions, increased by 35 percent to $13,370,812 in 2003 from $9,873,006 in 2002. In 2003 the Company spent $10,186,717 on drilling and completions, an increase of 160 percent over $3,915,021 spent in 2002. In 2003 the Company drilled 20 (14.5 net) wells compared to 13 (10.3 net) in 2002. Kensington drilled more horizontal wells and deeper wells in 2003 compared to 2002, which resulted in higher drilling costs per well. Of the total capital expenditures in 2003, 21 percent supported exploration activity and included land acquisitions of $964,651 (2002 – $1,073,427) and geological and geophysical spending of $1,818,375 (2002 – $894,805). Production facilities accounted for $3,108,116 (2002 – $1,036,900). In July 2003, the Company disposed of its interests in the mature Giroux Lake Unit for approximately $3,900,000.

Liquidity and Capital Resources

At December 31, 2003 Kensington had cash and short-term deposits of $6,127,433 and working capital of $3,361,160. The Company has an operating line of credit of $5 million which bears interest at the bank's prime lending rate plus 0.50 percent.

During 2003 the Company closed two private placement equity financings for gross proceeds of $16 million and net proceeds after underwriting fees and expenses of $14.8 million. Total capital expenditures of $13,370,812 in 2003 were funded by cash flow from operations of $5,556,426 and the balance from a portion of the proceeds of the two private-placement equity financings.

Subsequent to year-end the Company closed the acquisition of two private companies. The acquisitions were funded with a combination of cash, debt and the issuance of approximately 10.5 million common shares of Kensington. The Company was able to use its strong balance sheet to complete these acquisitions. On April 2, 2004 the Company entered into a "bought-deal" private placement for gross proceeds of $7.4 million. The Company will issue 5,296,021 shares on a flow-through basis.

The Company's operating line of credit was increased to $14,300,000 on closing the above noted acquisitions and the Company has increased the demand debenture pledged to $50,000,000.

Commitments

The Company has lease commitments for office space of $565,046 through 2007 and is also committed to purchasing $300,000 of seismic data prior to June 22, 2005. This seismic commitment was made to obtain preferential pricing on the seismic data that will be purchased in the normal course of business.

Business Risks

Exploration for, acquiring, developing, producing and marketing oil and natural gas involve a number of business risks and uncertainties which have the potential to significantly affect operating and financial results. These include exploration risk, reservoir performance, commodity prices, competition and government regulation.

Exploration risk relates to Kensington's ability to economically find and develop new reserves. This risk is mitigated by using skilled and experienced employees and consultants, focusing exploration efforts in areas in which we have existing knowledge and expertise, using the latest technologies and controlling costs to maximize profitability. The Company undertakes a certain portion of its exploration activities jointly with industry partners to allocate exploration risk appropriately within its capital program.

The prices that Kensington receives for oil, natural gas and natural liquids are volatile and subject to a number of external factors over which we have no control. The Company currently manages these risks by selling products through a combination of daily and monthly spot contracts through various purchasers. All contracts are short-term with 30-day termination notices. The Company intends to consider a price risk management program as its production base increases.

Forecast production from oil and natural gas reservoirs may decline more quickly than anticipated, resulting in lower cash flow and lower reserve recovery. In an effort to mitigate this risk, Kensington focuses on exploring for high-quality reservoirs with more predictable decline characteristics.

Competition for petroleum and natural gas leases and drilling prospects can be very intense at certain times in certain areas. Kensington attempts to mitigate this risk by avoiding areas where it believes that the economics of oil and natural gas production would be significantly reduced by intense competition.

The operations of oil and natural gas producers are subject to extensive controls and regulation by various levels of government, and there is risk that future changes in government policies and regulations could adversely impact Kensington's operations.

Corporate Outlook

With the closing of the acquisitions in the first quarter of 2004, Kensington is well positioned with a strong drilling prospect inventory to deliver continued growth.

Quarterly Information

Operating Margin Analysis

	2003				2002			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Production								
Oil and NGLs (bbls/d)	146	182	181	218	100	99	100	145
Natural gas (mcf/d)	1,652	3,426	4,605	5,581	1,003	835	898	1,462
Oil equivalent (boe/d)	421	753	948	1,148	267	238	249	388
Average prices								
Oil and NGLs ($/bbl)	45.71	26.45	33.60	31.01	28.53	39.37	38.96	42.57
Natural gas ($/mcf)	8.20	7.22	5.88	5.51	3.83	4.92	3.71	5.46
Oil equivalent ($/boe)	47.99	39.24	34.98	32.67	25.04	31.98	28.94	36.42
Dollars								
Petroleum and natural gas revenue	1,817,794	2,688,668	3,050,714	3,450,234	600,905	693,037	663,805	1,301,176
Royalties (net of ARTC)	303,154	480,876	648,440	1,062,633	90,823	120,027	116,047	214,688
Production costs	198,781	394,133	492,287	599,772	88,916	82,676	113,320	201,092
Operating netback	1,315,859	1,813,659	1,909,987	1,787,829	421,166	490,334	434,438	885,396
General and administrative – excluding stock-based compensation	265,420	465,420	251,895	224,027	149,576	197,106	164,043	201,067
Capital taxes	4,800	5,500	6,500	27,550	1,300	1,500	1,300	9,636
Interest and other income (expense)	(45,137)	1,231	7,484	16,626	17,427	38,633	8,867	(57,478)
Cash flow from operations	1,000,502	1,343,970	1,659,076	1,552,878	287,717	330,361	277,962	617,215
Depletion, depreciation and site restoration	537,005	806,480	942,815	1,196,220	222,850	226,570	273,430	464,390
Stock-based compensation	–	–	–	161,459	–	–	–	–
Future income taxes	181,600	(286,600)	256,000	39,200	27,270	51,130	2,600	49,336
Net income	281,897	824,090	460,261	155,999	37,597	52,661	1,932	103,489
$ per boe								
Petroleum and natural gas revenue	47.99	39.24	34.98	32.67	25.04	31.98	28.94	36.42
Royalties (net of ARTC)	8.00	7.02	7.44	10.06	3.79	5.54	5.06	6.01
Production costs	5.25	5.75	5.64	5.68	3.71	3.82	4.94	5.63
Operating netback	34.74	26.47	21.90	16.93	17.54	22.62	18.94	24.78
General and administrative – excluding stock-based compensation	7.01	6.80	2.89	2.12	6.23	9.10	7.15	5.63
Capital taxes	0.13	0.08	0.07	0.26	0.05	0.07	0.06	0.27
Interest and other income (expense)	(1.19)	0.02	0.08	0.16	0.73	1.79	0.38	(1.61)
Cash flow from operations	26.41	19.61	19.02	14.71	11.99	15.24	12.11	17.27
Depletion, depreciation and site restoration	14.18	11.77	10.81	11.33	9.29	10.46	11.91	13.00
Stock-based compensation	–	–	–	1.53	–	–	–	–
Future income taxes	4.79	(4.18)	2.93	0.37	1.14	2.36	0.11	1.38
Net income	7.44	12.02	5.28	1.48	1.56	2.42	0.09	2.89

Management's Report

The financial statements of Kensington Energy Ltd. were prepared by management in accordance with Canadian Generally Accepted Accounting Principles. The financial and operating information presented in this annual report is consistent with that shown in the consolidated financial statements.

Management has designed and maintains a system of internal controls to provide reasonable assurance that all assets are safeguarded and to facilitate the preparation of financial statements for reporting purposes. Timely release of financial information sometimes necessitates the use of estimates when transactions affecting the current accounting period cannot be finalized until future periods. Such estimates are based on careful judgments made by management.

External auditors appointed by the shareholders have conducted an independent examination of the corporate and accounting records in order to express their opinion on the financial statements.

The Board of Directors is responsible for ensuring that management fulfils its responsibilities for financial reporting and internal control. The Board exercises this responsibility through its Audit Committee. The Audit Committee, which consists of non-management directors has met with the external auditors and management in order to determine that management has fulfilled its responsibilities in the preparation of the financial statements. The Audit Committee has reported its findings to the Board of Directors who have approved the financial statements..

Donald S. Wood
President and Chief Executive Officer

Scott T. Bonli, CA
Vice President, Finance and
Chief Financial Officer

Calgary, Canada
April 2, 2004

Auditors' Report

To the Shareholders of Kensington Energy Ltd.

We have audited the balance sheets of Kensington Energy Ltd. as at December 31, 2003 and 2002 and the statements of income and deficit and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2003 and 2002 and the results of its operations and its cash flows for the years then ended in accordance with Canadian Generally Accepted Accounting Principles.

Ernst & Young LLP

Chartered Accountants

Calgary, Canada
March 5, 2004
(except for note 14 which is as of April 2, 2004)

Balance Sheets

As at December 31, ($)	2003	2002
Assets (note 5)		
Current		
Cash and cash equivalents	6,127,433	4,457
Accounts receivable	2,548,264	893,096
Prepaid expenses	61,228	62,952
	8,736,925	960,505
Property and equipment (note 4)	26,322,467	16,351,675
	35,059,392	17,312,180
Liabilities		
Current		
Bank indebtedness (note 5)	–	3,390,000
Accounts payable and accrued liabilities	5,375,765	1,220,751
	5,375,765	4,610,751
Site restoration	216,104	141,010
Future income taxes (note 8)	3,468,717	2,939,017
	3,684,821	3,080,027
Commitments and contingencies (notes 6, 10 & 11)		
Shareholders' Equity		
Share capital (note 6)	25,828,063	11,334,365
Contributed surplus (note 3)	633,747	472,288
Deficit	(463,004)	(2,185,251)
	25,998,806	9,621,402
	35,059,392	17,312,180

See accompanying notes to the financial statements

On behalf of the Board:

Thomas L. Love
Director

Richard R. Couillard
Director

Statements of Income and Deficit

For the years ended December 31, ($)	2003	2002
Revenues		
Petroleum and natural gas sales	11,007,410	3,258,923
Royalties	(2,811,703)	(683,285)
Alberta Royalty Tax Credit	316,600	141,700
Other income	30,171	28,231
	8,542,478	2,745,569
Expenses		
Production	1,684,973	486,004
General and administrative (note 3)	1,368,221	711,792
Interest	49,967	20,782
Depletion and depreciation	3,400,020	1,154,140
Site restoration	82,500	33,100
	6,585,681	2,405,818
Income before taxes	1,956,797	339,751
Taxes		
Capital taxes	44,350	13,736
Future income taxes (note 8)	190,200	130,336
	234,550	144,072
Net income for the year	1,722,247	195,679
Deficit, beginning of year	(2,185,251)	(2,380,930)
Deficit, end of year	(463,004)	(2,185,251)
Net income per common share (note 7)		
Basic	0.04	0.01
Diluted	0.04	0.01

See accompanying notes to the financial statements

Statements of Cash Flows

For the years ended December 31, ($)	2003	2002
Operating Activities		
Net income for the year	1,722,247	195,679
Add non-cash items		
Depletion and depreciation	3,400,020	1,154,140
Site restoration	82,500	33,100
Future income taxes	190,200	130,336
Stock based compensation (note 3)	161,459	–
Cash flow from operations	5,556,426	1,513,255
Changes in non-cash working capital items (note 9)	827,259	73,441
Cash provided by operating activities	6,383,685	1,586,696
Financing Activities		
Increase in bank indebtedness	2,819,030	3,390,000
Decrease in bank indebtedness	(6,209,030)	(630,000)
Issue of share capital	16,000,001	5,600
Share issue costs	(1,166,803)	–
Cash provided by financing activities	11,443,198	2,765,600
Investing Activities		
Expenditures on property and equipment	(17,318,498)	(9,873,006)
Sale of property and equipment	3,947,686	–
Site restoration costs incurred	(7,406)	(4,800)
Changes in non-cash working capital items (note 9)	1,674,311	(358,617)
Cash used in investing activities	(11,703,907)	(10,236,423)
Increase (decrease) in cash and cash equivalents	6,122,976	(5,884,127)
Cash and cash equivalents		
Beginning of year	4,457	5,888,584
End of year	6,127,433	4,457
Cash interest paid	49,967	20,782
Cash interest received	27,752	13,607
Cash capital taxes paid	21,143	7,124

See accompanying notes to the financial statements

Notes to the Financial Statements

1. *Description of Business*

Kensington Energy Ltd. (the "Company") was incorporated under the laws of the Province of Alberta on January 25, 1995 as 640773 Alberta Inc. On May 5, 1995, articles of amendment were filed to change the Company's name to Kensington Energy Ltd. The Company's business is the acquisition of petroleum and natural gas rights and the exploration for, development and production of, crude oil and natural gas in Canada.

2. *Summary of Significant Accounting Policies*

The financial statements have been prepared by management in accordance with Canadian Generally Accepted Accounting Principles. Because a precise determination of many assets and liabilities is dependent upon future events, the preparation of periodic financial statements necessarily involves the use of estimates and approximations. Accordingly, actual results could differ from those estimates. The financial statements have, in management's opinion, been properly prepared within reasonable limits of materiality and within the framework of the accounting principles summarized below.

Cash and cash equivalents

Cash and cash equivalents includes short-term deposits which are readily convertible into cash. Of the total cash and cash equivalents balance as at December 31, 2003 of $6,127,433 (2002 – $4,457), $5,000,000 (2002 – $nil) represents short term deposits with a maturity date of January 21, 2004 and an interest rate of 2.71 percent.

Property and equipment

Petroleum and natural gas properties

The Company follows the full cost method of accounting for its petroleum and natural gas activities, whereby all costs related to the acquisition of, exploration for and development of petroleum and natural gas properties and related reserves are capitalized. Such costs include land acquisition costs, geological and geophysical expenditures, costs of drilling both productive and non-productive wells, tangible production equipment and that portion of general and administrative expenditures related to acquisition, exploration and development activities. Proceeds from the disposal of petroleum and natural gas properties and production equipment are applied as a reduction of the cost of the remaining assets, except when such a disposal would change the depletion and depreciation rate by more than 20 percent, in which case a gain or loss on disposal would be recorded.

Capitalized costs of petroleum and natural gas properties and production equipment, excluding the cost of unproved properties, are depleted and depreciated using the unit-of-production method and based on estimated proven reserves of petroleum and natural gas before royalties as determined by an independent reserve engineer converting natural gas to an oil equivalent basis using six thousand cubic feet of natural gas for one barrel of petroleum. Unproved properties are not included in the depletion base until such time that proven reserves have been established.

The Company applies a ceiling test to capitalized costs on a quarterly basis to ensure that such costs do not exceed the estimated undiscounted future net revenues from production of gross proven reserves, plus the cost of undeveloped properties net of impairment, less amounts associated with future general and administrative costs, financing costs and income tax expense. The calculation of future net revenues is based on sales prices, costs and regulations in effect at the period end.

Computer equipment and furniture

Computer equipment and furniture is recorded at cost and is depreciated at 25 percent on a declining balance basis.

Site restoration

Future site restoration costs of the Company's petroleum and natural gas properties are estimated by reference to costs currently experienced by the Company. The estimated expense is reduced by expected equipment salvage values at the time of abandonment. The resulting net estimated expense, if any, is amortized to earnings over the remaining life of the Company's reserves on a unit of production basis. Actual expenditures incurred are applied against the accumulated provision account.

Revenue recognition

Petroleum and natural gas sales is recognized in income when reserves are produced and delivered to the purchaser.

Flow-through shares

The resource expenditure deductions for income tax purposes related to exploratory and development activities funded by flow-through share arrangements are renounced to investors in accordance with tax legislation. Under the liability method of accounting for income taxes, the future income taxes related to the temporary differences arising at the time of renunciation are recorded at that time, together with a corresponding reduction to the carrying value of the shares issued.

Joint activities

Substantially all of the Company's petroleum and natural gas activities are conducted jointly with others. These financial statements reflect only the Company's proportionate interest in such activities.

Measurement uncertainty

The amounts recorded for depletion and depreciation of property and equipment and the provision for future site restoration costs and the ceiling test calculation are based on estimates of proven reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect of changes in such estimates on the financial statements in future periods could be significant.

Stock options

Under the Company's stock option plan, options to purchase common shares are granted to directors, officers and employees at current market prices. Options issued by the Company in 2003 are accounted for in accordance with the fair value method of accounting for stock-based compensation, and as such the cost of the option is charged to income with an offsetting amount recorded to contributed surplus, based on an estimate of the fair value determined using a Black-Scholes Option Pricing Model. No compensation expense has been recorded on options issued prior to January 1, 2003 (see note 6).

Per common share amounts

The Company follows the treasury stock method for the computation and disclosure of diluted per common share amounts. Under this method, the diluted weighted average number of common shares is calculated assuming the proceeds from the exercise of "in the money" options are used to purchase common shares at the average market price.

Income taxes

The Company follows the liability method of tax allocation in accounting for income taxes. Under this method, the Company records future income taxes for the effect of any differences between the accounting and income tax basis of an asset or liability (temporary differences). Future income tax assets and liabilities are measured using income tax rates expected to apply in the years in which temporary differences are expected to be recovered or settled. The effect on future income tax assets and liabilities of a change in tax rates is recognized in net income in the period in which the change is substantially enacted.

3. *Changes in Accounting Policies*

Stock-based compensation

Effective January 1, 2003, the Company adopted the recommendations of the Canadian Institute of Chartered Accounts ("CICA") on accounting for stock-based compensation. As permitted by this new pronouncement, the Company prospectively adopted the fair value method of accounting for stock options granted to employees and directors. Stock-based compensation is recorded in the statement of income as general and administrative expense for all options granted on or after January 1, 2003, with a corresponding increase recorded as contributed surplus. Compensation expense for options is based on the estimated fair values at the time of the grant and the expense is recognized over the vesting period of the option. Using the following assumptions: volatility factor of expected market price of 64.7 percent, a weighted average risk-free interest rate of 4.29 percent, no dividend yield and a weighted average expected life of options of 4 years; the fair value of options granted in 2003 was $678,120, of which $161,459 was recognized as general and administrative expense in the 2003 statement of income based on when these options vest. There is no impact on basic and diluted net income per share figures. Upon the exercise of the stock options, consideration paid together with the amount previously recognized in contributed surplus is recorded as an increase in share capital. The Company has not incorporated an estimated forfeiture rate for stock options that will not vest; rather, the Company accounts for forfeitures as they occur. In the event that vested options expire without being exercised, previously recognized compensation expense associated with such stock options is not reversed. For options granted prior to January 1, 2003, the Company continues to disclose the pro forma earnings impact of related stock-based compensation expense as is permitted by the new accounting pronouncement (see note 6).

Flow-through shares

In 2003, the Company prospectively adopted the recommendation of the Emerging Issues Committee of the CICA on flow-through shares, which requires the recognition of the foregone tax benefits at the time of renouncement provided there is reasonable assurance that the expenditures will be incurred. Prior to 2003, the tax effect of the renouncement was recorded when the corresponding exploratory and development expenditures were incurred.

4. *Property and Equipment*

($)	December 31, 2003 Cost	Accumulated Depletion and Depreciation	Net Book Value
Petroleum and natural gas properties and production equipment	38,775,646	12,587,851	26,187,795
Computer equipment and furniture	265,503	130,831	134,672
	39,041,149	12,718,682	26,322,467

($)	December 31, 2002 Cost	Accumulated Depletion and Depreciation	Net Book Value
Petroleum and natural gas properties and production equipment	25,470,093	9,221,851	16,248,242
Computer equipment and furniture	200,244	96,811	103,433
	25,670,337	9,318,662	16,351,675

As at December 31, 2003, unproved properties with a cost of $2,809,062 (2002 – $1,026,787) have been excluded from costs subject to depletion.

5. *Bank Indebtedness*

As at December 31, 2003, the Company has a $5,000,000 operating line of credit (2002 – $4,400,000), due on demand and bearing interest at the bank's prime lending rate plus 0.50 percent (2002 – bank prime plus 0.75 percent). The Company has pledged as collateral on this facility a general security agreement and a first floating-charge demand debenture of $10,000,000 over all of the Company's assets. The credit facility is reviewed by the bank annually.

As at December 31, 2003 $nil (2002 – $3,390,000) was drawn on this facility by the Company.

6. *Share Capital*

a) Authorized

Unlimited number of Class A common shares, voting, with no par value.

b) Issued and outstanding

	2003		2002	
	Number of Shares	$	Number of Shares	$
Class A Shares				
Balance, beginning of year	29,428,426	11,334,365	29,400,426	12,660,965
Common shares issued	18,400,000	14,000,000	–	–
Flow-through shares issued	1,290,323	2,000,001	–	–
Stock options exercised	–	–	28,000	5,600
Share issue costs, net of future income taxes	–	(691,303)	–	–
Tax benefits relating to qualifying expenditures renounced	–	(815,000)	–	(1,332,200)
Balance, end of year	49,118,749	25,828,063	29,428,426	11,334,365

c) Flow-through shares issued

On November 19, 2003, the Company issued 1,290,323 flow-through Class A shares and renounced resource expenditures of $2,000,001. The effect of the renouncement of these expenditures was an increase in future income taxes and a decrease in share capital of $815,000 (2002 – $1,332,200). During 2003, the Company incurred qualifying expenditures relating to flow-through shares of $36,743 (2002 – $3,174,427l). The Company is committed to incur the remaining $1,963,258 of qualifying expenditures during fiscal 2004.

d) Common shares issued

On March 27, 2003, the Company closed a private placement of 12,000,000 Class A common shares at $0.50 per share for total gross proceeds of $6,000,000. The financing was done on a "bought deal" basis for $5,500,000 and increased by the exercise of an over allotment option for $500,000.

On November 19, 2003, the Company closed a private placement of 6,400,000 Class A common shares at $1.25 per share for total gross proceeds of $8,000,000. The financing was done on a "bought deal" basis for $6,000,000 and increased by the exercise of an over allotment option for $2,000,000.

e) Stock option plan

The Company has established a stock option plan whereby the Company may grant options to its directors, officers and employees at the current market price for up to 10 percent of the issued Class A shares. Stock options vest evenly over a three-year period commencing a year from the date of grant and expire five years after the date of grant.

The following is a continuity of stock options outstanding for which shares have been reserved:

	2003		2002	
	Shares	Weighted-Average Exercise Price ($)	Shares	Weighted-Average Exercise Price ($)
Opening	**1,250,000**	**0.29**	1,105,000	0.23
Granted	**1,666,000**	**0.75**	790,000	0.35
Exercised	**–**	**–**	(28,000)	0.20
Cancelled/expired	**(14,000)**	**0.55**	(617,000)	0.27
	2,902,000	**0.57**	1,250,000	0.29

The following summarizes information about stock options outstanding at December 31, 2003:

	Options Outstanding			Options Exercisable	
Range of Exercise Price ($)	Number Outstanding at December 31, 2003	Weighted-Average Remaining Contractual Life (years)	Weighted-Average Exercise Price ($)	Number Exercisable at December 31, 2003	Weighted Average-Exercise Price ($)
0.20-0.22	636,000	2.63	0.22	446,000	0.22
0.32-0.39	600,000	3.40	0.35	200,000	0.35
0.46-0.66	565,000	4.21	0.48	–	–
0.84-0.95	971,000	4.45	0.84	–	–
1.30-1.33	130,000	4.85	1.30	–	–
	2,902,000			646,000	

f) Stock-based compensation

As discussed in note 3, the Company continues to disclose the pro forma effect of stock-based compensation on net earnings and earnings per basic and diluted share related to stock options granted in 2002. For purposes of this pro-forma disclosure, the Company calculated the fair value of stock-based compensation at the date of grant using a Black-Scholes Option Pricing Model. The estimated fair value of options is amortized to expense over the options' vesting periods. For stock options granted in 2002 the Company's net earnings would be reduced by $40,880 for the year ended December 31, 2003 and by $27,460 for the year ended December 31, 2002. There would be no impact on basic and diluted net income per share figures for 2003 or 2002.

In calculating the fair value of the options granted in 2002, the assumptions made for the options granted for 2002 include a volatility factor of expected market price of 66.1 percent, a weighted average risk-free interest rate of 4.43 percent, no dividend yield and a weighted average expected life of options of 4 years. The pro forma amounts shown above do not include the compensation cost associated with stock options granted prior to January 1, 2002. The fair value of the 2002 common share options was estimated to be $122,600.

7. *Weighted Average Number of Common Shares*

The following table summarizes the common shares used in calculating basic and diluted net income per common share.

Weighted average number of common shares outstanding during the year	2003	2002
Basic	39,485,943	29,419,988
Diluted	40,721,879	29,802,518

Diluted earnings per share reflects the dilutive effect of the exercise of stock options outstanding which are "in the money," meaning that their exercise price exceeds the average market price of the Company's common shares for the year. Shares of 1,235,937 (2002 – 382,530) were added to the basic weighted average number of common shares outstanding during the year in the calculation of diluted per share amounts. Adjustments to the numerator amounts were not required.

8. *Future Income Taxes*

The Company has an effective tax rate which differs from the expected Canadian income tax rate. The differences are as follows:

($)	2003	2002
Statutory income tax rate	40.75%	42.25%
Computed expected provision	797,395	143,545
Increase (decrease) resulting from:		
Non-deductible crown charges	609,900	261,226
Alberta royalty tax credit	(122,565)	(59,868)
Resource allowance	(597,025)	(156,498)
Attributed Alberta royalty deduction	(4,850)	(35,595)
Rate adjustment	(515,100)	(13,108)
Stock-based compensation	65,794	–
Other	(43,349)	(9,366)
Future income taxes	190,200	130,336

At December 31, 2003, the Company has available for deduction against future taxable income undepreciated capital cost, Canadian oil and gas property expense, Canadian exploration expense, and Canadian development expense aggregating approximately $16,995,000 (2002 – $8,636,000).

Future income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts for income tax purposes. The components of the Company's future income tax assets and liabilities are as follows:

($)	2003	2002
Net book value of capital assets in excess of tax pools	4,048,598	3,245,135
Future site restoration costs	(72,468)	(59,393)
Share issue costs	(409,458)	(112,846)
Rate reduction from resource allowance	–	(39,373)
Attributed Alberta Royalty Deduction	(97,955)	(94,506)
Future income tax liability	3,468,717	2,939,017

9. *Net Change in Non-Cash Working Capital Items*

($)	2003	2002
Accounts receivable	(1,655,168)	(570,102)
Prepaid expenses	1,724	(11,384)
Accounts payable and accrued liabilities	4,155,014	296,310
	2,501,570	(285,176)

The change in non-cash working capital relates to the following activities:

	2003	2002
Operating	827,259	73,441
Investing	1,674,311	(358,617)
	2,501,570	(285,176)

10. *Commitments*

The Company has lease commitments for office space as follows:

($)	
2004	82,796
2005	153,003
2006	160,750
2007	168,497
	565,046

The Company is also committed to purchasing $300,000 of seismic data prior to June 22, 2005. This commitment was made to obtain preferential pricing on the seismic data that will be purchased in the normal course of business.

11. *Contingencies*

The Company is party to various legal claims associated with the ordinary conduct of business. The Company does not anticipate that these claims will have a material impact on the Company's financial position.

12. *Financial Instruments*

Fair value of financial assets and liabilities

The fair values of financial instruments comprising cash equivalents, accounts receivable, accounts payable and accrued liabilities and bank indebtedness approximate their carrying values.

Risk management

The nature of operations and the issuance of debt expose the Company to fluctuations in commodity prices, foreign currency exchange rates and interest rates. The Company manages these risks by selling products through a combination of daily and monthly spot contracts through various purchasers. All contracts are short-term with 30 day termination notices. In addition, borrowings under bank credit facilities are for short periods and are market rate based (variable interest rates); thus carrying values approximate fair values.

The nature of the Company's operations result in exposure to fluctuations in commodity prices and interest rates. As of December 31, 2003 and 2002 no contracts to manage exposure to these risks were in place.

Accounts receivable includes amounts receivable for petroleum and natural gas sales which are generally made to large creditworthy purchasers, and amounts receivable from joint venture partners which are recoverable from production. Accordingly, the Company views credit risk on these amounts as low.

13. *Comparative Figures*

Certain comparative figures have been reclassified to conform to the current year's financial statement presentation.

14. *Subsequent Events*

Acquisitions

On February 27, 2004, the Company purchased all of the issued and outstanding shares of Durness Resources Inc. ("Durness"), a private company, for $3,771,800 in cash. On March 3, 2004, the Company disposed of certain assets acquired from Durness for cash proceeds of $558,000 subject to closing adjustments.

On March 25, 2004, the Company purchased all of the issued and outstanding shares of Revolution Energy Inc., a private company, by issuing 10,516,951 Class A shares of the Company and paying $7,510,965 in cash.

Debt facility

The Company's operating line of credit was increased to $14,300,000 on closing the above noted acquisitions and the Company has increased the demand debenture pledged to $50,000,000.

Private Placement

On April 2, 2004 the Company entered into a financing agreement on a "bought deal" basis for the private placement of 5,296,021 Class A shares of the Company at a price of $1.40 per share to be issued on a flow-through basis. The Company will be required to renounce qualifying Canadian exploration expenses in the amount of the gross proceeds of $7,414,429 to subscribers for the 2004 taxation year.

Historical Summary

Years ended December 31	2003	2002	2001	2000	1999
Revenue					
Petroleum and natural gas sales [1]	11,007,410	3,258,923	2,129,287	2,203,200	1,548,808
Royalties, net of ARTC	2,495,103	541,585	(345,738)	(411,262)	(156,209)
Interest and other	30,171	28,231	1,421	1,449	15,272
	8,542,478	2,745,569	1,784,970	1,793,387	1,407,871
Expenses					
Production	1,684,973	486,004	325,833	302,063	168,581
General and administrative	1,368,221	711,792	450,936	210,738	209,008
Depletion, depreciation and site restoration	3,482,520	1,187,240	561,920	817,403	581,220
Interest	49,967	20,782	68,403	112,227	115,665
	6,585,681	2,405,818	1,407,092	1,442,431	1,074,474
Income before taxes	1,956,797	339,751	377,878	350,956	333,397
Net income	1,722,247	195,679	258,866	189,719	333,397
Cash flow from operations	5,556,426	1,513,255	932,978	1,168,359	914,617
Balance Sheet Information					
Capital expenditures, net	13,370,812	9,873,006	1,825,814	565,302	883,816
Bank indebtedness	–	3,390,000	630,000	810,000	1,400,000
Working capital (deficiency)	3,361,160	(3,650,246)	4,708,705	(696,851)	(317,602)
Shareholders' equity	25,998,806	9,621,402	10,752,323	3,428,151	2,482,213
Common shares outstanding – basic	49,118,749	29,428,426	29,400,426	10,142,776	5,177,276
Per share data – diluted					
Net income	0.04	0.01	0.02	0.02	0.06
Cash flow from operations	0.14	0.05	0.08	0.14	0.08
Operating					
Production					
Oil and NGLs (bbls/d)	182	111	111	137	150
Natural gas (mcf/d)	3,829	1,050	386	139	170
Oil equivalent (boe/d)	820	286	175	160	178
Proved Reserves					
Oil and NGLs (mbbls)	550	307	284	311	314
Natural gas (mmcf)	8,907	5,350	3,014	1,042	911
Oil equivalent (mboe)	2,035	1,199	786	485	466
Proved plus Probable Reserves [2]					
Oil and NGLs (mbbls)	729	642	330	583	590
Natural gas (mmcf)	10,575	10,755	3,696	2,071	2,639
Oil equivalent (mboe)	2,491	2,435	946	929	1,030
Drilling Activity					
Gross wells	20	13	4	4	1
Net wells	14.5	10.3	2.4	0.9	0.4

(1) Includes hedging in 1999 and 2000

(2) Represents established reserves for 1999-2002

Corporate Information

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Thomas L. Love (1) (2) (3)
Independent Businessman

Donald S. Wood
President and Chief Executive Officer
Kensington Energy Ltd.

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(2) Reserves Committee
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(4) Corporate Governance Committee

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Scott T. Bonli, CA
Vice President, Finance and
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Corporate Secretary

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Stock Exchange Listing

Toronto Stock Exchange
Class A Shares
Trading Symbol: KNN

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Abbreviations

bbls	barrels
bbls/d	barrels per day
boe	barrels of oil equivalent [1]
mboe	thousand barrels of oil equivalent
boe/d	barrels of oil equivalent per day
mbbls	thousand barrels
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmbtu	million British thermal units
mmcf	million cubic feet
mmcf/d	million cubic feet per day
NGLs	natural gas liquids

[1]Natural gas is equated to oil on the basis of 6,000 cubic feet or six mcf = one barrel

This disclosure contains certain forward-looking statements that involve substantial known and unknown risks and uncertainties, certain of which are beyond Kensington's control, including: the impact of general economic conditions in Canada and the United States, industry conditions, changes in laws and regulations including the adoption of new environmental laws and regulations and changes in how they are interpreted and enforced, increased competition, the lack of availability of qualified personnel or management, fluctuations in foreign exchange or interest rates, stock market volatility and market valuations of companies with respect to announced transactions and the final valuations thereof, and obtaining required approvals of regulatory authorities. Kensington's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurances can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits, including the amount of proceeds, that Kensington will derive therefrom.

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